ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, et al.,	)	
	)	
Petitioners,	)	
	)	No. 24-1120
v.	)	
	)	consolidated with Nos.
ENVIRONMENTAL PROTECTION	)	24-1121, 24-1122, 24-1124,
AGENCY AND MICHAEL S.	)	24-1126, 24-1128, 24-1142,
REGAN, ADMINISTRATOR,	)	24-1143, 24-1144, 24-1146,
UNITED STATES	)	24-1152, 24-1153, 24-1155
ENVIRONMENTAL PROTECTION	)	
AGENCY,	)	
	)	
Respondents.	)	

OPPOSITION OF ENVIRONMENTAL AND PUBLIC HEALTH
RESPONDENT-INTERVENORS TO PETITIONERS' STAY MOTIONS

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GLOSSARY

CCS	Carbon Capture and Storage
EEI	Edison Electric Institute
EGST	Electric Generators for a Sensible Transition
EPA	United States Environmental Protection Agency
NRECA	National Rural Electric Cooperative Association
Rule	New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024)
TSD	Technical Support Document

INTRODUCTION

Thirteen years ago, the head of one of the nation's largest electric generation companies stated that it had "demonstrated to a certainty that carbon capture and storage is in fact a viable technology." American Electric Power Earnings Call (2011).[1] The only impediment to further deployment was the absence of federal greenhouse gas emission limits, which complicated the company's ability to obtain approval to recover its costs. *Id.*; 89 Fed. Reg. 39,798, 39,813 (May 9, 2024) ("the Rule"). The U.S. Environmental Protection Agency (EPA) has now provided that missing ingredient. Nonetheless, contrary to its "certainty" more than a decade ago that carbon capture and storage (CCS) was demonstrated and viable, American Electric Power and other stay movants ("Movants") now claim that a standard based on CCS cannot be met by 2032. *E.g.*, Motion of Electric Generators for a Sensible Transition, ECF No. 2056364 ("EGST Mot.") vi, 7-8. EPA's rulemaking record shows otherwise.

In this Rule, EPA set emission limits for carbon dioxide pollution based on CCS. The Rule provides long lead times and numerous flexibilities. A robust factual record shows that the technology is adequately demonstrated, achievable at

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[1] *See* Env't Def. Fund Comments at 81 n.399, EPA-HQ-OAR-2023-0072-0764; call transcript available at: web.archive.org/web/20130927115501/https:/www.morningstar.com/earnings/PrintTranscript.aspx?id=28688913.

reasonable cost, and will not undermine the reliability of the electric grid. 42 U.S.C. § 7411(a)(1).

Movants have not made the required showing that they are likely to succeed on the merits or will suffer irreparable harm during the period of merits litigation. Near-term planning costs for states and utilities under the Rule are modest, and there is no near-term need for significant capital costs. On the other hand, a stay will significantly harm the public interest. Power plants are by far the largest stationary source emitters of greenhouse gases in the country. Carbon dioxide released as a result of delaying the Rule will stay in the atmosphere for more than a century, worsening the devastating impacts of climate change already evident, from unprecedented heat waves to devastating storms.

The stay motions should be denied.

ARGUMENT

To obtain a stay, Movants must establish that (1) they are likely to succeed on the merits; (2) they will be irreparably harmed in the absence of relief; (3) the equities favor an injunction; and (4) an injunction is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 425-26 (2009); *Winter v. NRDC*, 555 U.S. 7, 22 (2008). Movants fail on all four factors.

I. Movants are unlikely to succeed on the merits

A. EPA may set performance standards based on technology that is adequately demonstrated but not already in widespread use

Under Clean Air Act Section 111, a "standard of performance" must "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction" that EPA "determines has been adequately demonstrated." 42 U.S.C § 7411(a)(1). EPA must consider cost, nonair quality health and environmental impacts, and energy requirements. *Id.* In balancing these factors, the agency exercises "a great degree of discretion." *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999); *see also Am. Elec. Power Co. v. Conn.*, 564 U.S. 410, 427 (2011) (statute entrusts "complex balancing" to EPA).

Movants suggest that emission limits may be based only on technology that is already in widespread, commercial use. *See, e.g.*, Motion of Ohio et al., ECF No. 2055522 ("Ohio Mot.") 7; Motion of Edison Electric Institute, ECF No. 2056352 ("EEI Mot.") 23 (arguing that *after* EEI's members deploy CCS, *then* "EPA can commence" a rulemaking). But the Clean Air Act does not impose this limitation. Elsewhere, Movants acknowledge that the legal standard is not so demanding: it simply requires that a system "has been shown to be reasonably reliable, reasonably efficient," and is reasonably expected to control pollution "without becoming exorbitantly costly." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *accord* Ohio Mot. 10; EEI Mot. 6; Motion of West Virginia et al., ECF No. 2054190 ("WV Mot.") 6. Thus an "achievable" standard "need not necessarily be routinely achieved within the industry prior to its adoption,"

although it cannot be "purely theoretical or experimental." *Essex*, 486 F.2d at 433-34; *see also Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92, 401-02 (D.C. Cir. 1973) (allowing for reasonable "projection[s]" and "extrapolations"); *Lignite*, 198 F.3d at 934 ("extrapolat[ing]" from performance in other industries). EPA's emission limits easily meet this standard.

B. CCS is the best system of emission reduction adequately demonstrated and the Rule's standards are achievable

An exhaustive record supports each aspect of EPA's determination that carbon capture and sequestration with a 90 percent capture rate is adequately demonstrated, achievable, cost-reasonable, and will not harm the reliability of the electric grid. Movants largely ignore EPA's reasoned, record-based conclusions, and instead proffer assertions that are extra-record and conclusory.[2] They have not shown a likelihood of success on the merits, particularly because EPA's determinations regarding pollution technology go to the heart of the agency's technical expertise. *See Lignite*, 198 F.3d at 933 (deferring to EPA's scientific judgment).

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[2] Because a merits judgment must be determined based on the record, 42 U.S.C. § 7607(d)(7)(A), the likelihood of success on the merits should also be determined based on the record. Movants inappropriately and repeatedly cite extra-record declarations for merits purposes. WV Mot. 15; Ohio Mot. 15-18; Motion of National Rural Electric Cooperative Association, ECF No. 2054191 ("NRECA Mot.") 11-13, 15-16.

1. Ninety percent carbon capture is adequately demonstrated and achievable

EPA reasonably applied its technical expertise to determine that carbon capture systems can run continuously, treat units' entire exhaust stream, and achieve 90 percent capture on an annual average basis. The capture process was first patented in the 1930s. 89 Fed. Reg. at 39,813. Since then, it has been applied across various industries, demonstrated at power plants, tested for thousands of hours, and analyzed in dozens of technical engineering studies on a variety of designs. *See generally id*. at 39,846-54. Today, commercial vendors offer guarantees that their equipment will remove 90 percent of the carbon dioxide from a power plant's exhaust. *Id.* at 39,851-52.

At least fifteen carbon capture and storage projects are operating in the U.S. today and another 121 are in construction or advanced stages of development. *Id.* at 39,813-14. EPA's record includes successful deployment across different industrial applications, including commercial scale power plants. The coal-fired Boundary Dam Unit 3 "consistently achieved 90 percent capture rates" in the processed slipstream, Petra Nova "successfully captured 92.4 percent" from the slipstream during operation, and the gas-fired Bellingham Energy Center had an 85-95 percent capture rate from 1991 to 2005. *Id.* at 39,848, 39,850, 39,925.

Movants try to discount these examples. First, they point to early technical challenges in some projects, *see* WV Mot. 7, Motion of National Rural Electric

Cooperative Association, ECF No. 2054191 ("NRECA Mot.") 10, but EPA reasonably concluded, and extensively explained, why those "have been sufficiently overcome," 89 Fed. Reg. at 39,848; *id.* at 39,848-49. Second, Movants try to undermine the capture rates achieved at the projects. At Boundary Dam, for instance, Movants claim the capture rate fell short of 90 percent, because the unit captured 90 percent from a "slipstream"—a portion of the full plant's exhaust. Motion of National Mining Association et al., ECF No. 2056359 ("NMA Mot.") 12; *id.* at 11 (similar claims about Petra Nova). But EPA reasonably concluded that slipstream projects help demonstrate that 90 percent capture is viable at full, commercial-scale units, because there are no technological impediments to scaling up from a slipstream to a full unit. *See* 89 Fed. Reg. at 39,848-49 (explaining that the Boundary Dam capture unit was designed to capture less than the full plant's exhaust because of contract requirements, limited incentives, and limited regulatory requirements, and that "improvements can be implemented in future CCS deployments"); *id.* at 39,837 ("Technology providers have decades of experience and have done the work to responsibly scale up the technology . . . ."); *see also id.* at 39,852 (noting that in 2011, American Electric Power "did not cite any technology concerns" with full-scale CCS installation).

Carbon is generally captured by running exhaust through a liquid solvent. *Id.* at 39,848. Treating more exhaust merely requires a larger container to hold more

solvent. For example, in 2011, a capture unit that demonstrated 90 percent reduction at the 25-megawatt Plant Barry was scaled up tenfold in 2017 to capture 90 percent of the emissions from the 240-megawatt Petra Nova plant, using the exact same solvent. *Id.* at 39,849-50, 39,852. The same vendor is planning for 95 percent removal from a project double the size of Petra Nova, the 530-megawatt Project Tundra, *id.* at 39,850-51, and is now performing an engineering design study for the full exhaust of two units totaling approximately 1,500 megawatts, at Four Corners. EPA, Greenhouse Gas Mitigation Measures for Steam Generating Units (Technical Support Document), EPA-HQ-OAR-2023-0072-9095 (Apr. 2024) ("Coal TSD") at 30-31; Navajo Transitional Energy Company Comments, EPA-HQ-OAR-2023-0072-0819 at 2, 10 n.39 (citing FEED study announcement).

EPA's record supporting the adequate demonstration of CCS far exceeds what this Court has held sufficient in other cases. *See Essex*, 486 F.2d at 429, 435-37, 440 (finding standard "achievable" even though only one plant in the country was running the technology and it was not yet achieving the proposed standard, and upholding another standard based on "tests of prototype and full-scale control systems, considerations of available fuel supplies, literature sources, and documentation of manufacturer guarantees and expectations"); *Lignite*, 198 F.3d at 933-34 & n.3 (upholding standards in the absence of emissions data regarding the technology's application to the relevant equipment).

2. Transport and storage infrastructure for captured carbon is adequately demonstrated

The Rule's carbon emission standard is achieved "at the [power plant] stack." 89 Fed. Reg. at 39,845-46. Operators are not responsible for running carbon transport and storage facilities; their responsibility is to transfer the captured carbon to a sequestration facility that reports to EPA. *Id.* at 39,951. It is not unusual for standards to create a need for proper disposal of captured emissions. *See, e.g.*, 44 Fed. Reg. 33,580, 33,603-04 (1979) (analyzing changes in sludge disposal costs for rule limiting air pollution from power plants). In that circumstance, EPA must consider the consequences of managing the waste, *Essex*, 486 F.2d at 438-39, but that need does not render a pollution standard invalid.

Relying on comprehensive assessments by the Department of Energy and the U.S. Geological Survey, EPA found that carbon sequestration resources "are widely available across the nation," and there is "appropriate geology" to store as much as 21,000 billion metric tons of carbon dioxide (relative to the expected 1.3 billion stored under this Rule). 89 Fed. Reg. at 39,846, 39,862-63. That companies will need to obtain permits for specific well sites does not render EPA's conclusions "speculative," *contra* Ohio Mot. 17. Tens of millions of tons of carbon dioxide have already been stored underground, 89 Fed. Reg. at 39,847, and dozens of sequestration projects are ongoing, some in Movants' own states, *id.* at 39,864. More than 90 percent of the existing coal-fired plants that expect to operate after

2038 are within 100 miles of potential sequestration sites, and more than 50 percent are within 20 miles. *Id.* at 39,863-64. The pipeline industry is fully capable of building pipelines over much longer ranges. *See id.* at 39,857 (citing, e.g., carbon pipelines of 500 and 232 miles).

EPA assessed the pipeline buildout that could be triggered by the Rule using multiple conservative assumptions. First, EPA's analysis incorporated all coal plants that have not yet announced retirements before 2039, even though by then nearly half of those will have reached the historical average age of retirement. *Id.* at 39,856, 39,876. Second, EPA assumed each plant will build its own pipeline, although pipelines generally serve multiple customers. *See id*. at 39,856. Finally, EPA assumed no plants will tap into existing or proposed pipelines, although 5,385 miles of carbon pipelines already exist. *Id.* Even with these assumptions, EPA concluded that a maximum of 5,000 miles of pipelines would need to be constructed by 2032—well within the recent build rate for gas pipelines. *Id.*

3. CCS is a cost-reasonable control

Using a variety of metrics, EPA determined that the cost of CCS is reasonable and comparable to costs from prior rulemakings. 89 Fed. Reg. at 39,840-41. EPA's cost analysis used Department of Energy studies, the latest vendor information, and considerations of power plant capacity factor, gas prices, amortization rates, and tax incentives. Coal TSD at 50-57; EPA, Greenhouse Gas

Mitigation Measures: Carbon Capture and Storage for Combustion Turbines (Technical Support Document), EPA-HQ-OAR-2023-0072-9099 (Apr. 2024) ("Gas TSD") at 5-20. EPA reasonably considered the tax credits and grants that Congress made available to reduce companies' costs of applying carbon capture systems, 89 Fed. Reg. at 39,800, properly concluding that the Inflation Reduction Act tax credit "is generally sufficient to defray the capital costs of CCS and much, if not all, of the operating costs." *Id.* at 39,902.

EPA determined that a coal-fired plant that installs carbon capture by 2032 is expected to operate for 12 years, *id.* at 39,880, a timeframe over which it would actually be *making* money due to congressional incentives. Coal TSD at 54 tbl.11 & n.125. In the case of gas-fired plants, EPA determined that the cost of CCS was $81 to $95 per metric ton ("tonne"), Gas TSD at 12 fig.7—approximately $74 to $86 per ton. This is comparable to the cost of other Clean Air Act standards, such as the 2015 standards for the oil and gas industry. 89 Fed. Reg. at 39,879 ($98 per ton of carbon dioxide equivalent). Movants' vague assertions about "exorbitant[]" costs or "billions" of dollars per unit are based on extra-record, inadequately supported submissions. *E.g.*, EGST Mot. 19 (citing, e.g., Ballew Declaration ¶ 12, "project[ing]" that costs "could exceed $5 billion" without explanation or support). These are inadequate to supplant EPA's rigorous, record-based technical analysis, and do not rebut EPA's explanation that CCS's per-ton cost is reasonable.

4. EPA properly considered energy requirements in setting the standards

EPA, the "primary regulator of greenhouse gas emissions," must also consider "our Nation's energy needs" when determining the best system of emission reduction. *Am. Elec. Power Co.*, 564 U.S. at 427-28. Here, EPA evaluated existing and projected trends in the electric generation resource mix, *see generally* EPA, Power Sector Trends (Technical Support Document), EPA-HQ-OAR-0072-8920 (Apr. 2024) ("Power Sector Trends TSD"), properly conferred and worked with federal and regional entities that have authority over the system's reliability and affordability, including the Federal Energy Regulatory Commission, 89 Fed. Reg. at 39,803, and determined that there will be continued resource adequacy, *see generally* EPA, Resource Adequacy Analysis (Technical Support Document), EPA-HQ-OAR-0072-8916 (Apr. 2024) ("Resource TSD").

Because EPA focused the CCS-based standards only on a small (and shrinking) portion of the electric generation fleet—long-lived coal plants and the largest, most frequently-run new gas plants—the Rule has limited impact on grid resources and overall "reliability." Of the 181 gigawatts of coal-fired capacity currently online, 87 gigawatts have already publicly announced plans to retire before 2039 and another 13 gigawatts have announced they will switch to gas. 89 Fed. Reg. at 39,876. EPA projects an additional 39 gigawatts will retire for economic reasons irrespective of the Rule, leaving only 42 gigawatts of coal

projected to still be running long enough to be subject to a CCS-based standard. *Id.* Likewise, most new gas plants coming online in the next decade are not expected to run frequently enough to be subject to the Rule's most stringent CCS-based standard; rather, they will serve in flexible, low-load capacities to complement the growth of intermittent renewable generation. *Id.* at 39,823.

Given these realities, EPA's modeling shows that the Rule will not cause any region to experience more than a 1 percent change in its reserve capacity, meaning there will be little impact on any region's need to build or import capacity to maintain reserve margins. *See* Resource TSD at 11. In fact, EPA projects that in 2040, "nearly the same amount of electricity" will be generated by coal-fired units with or without the Rule. 89 Fed. Reg. at 39,900.

C. The Rule squarely conforms to statutory text and precedent

The Rule sets precisely the "traditional" type of technology-based standards that, as the Supreme Court affirmed, Section 111 authorizes. *West Virginia v. EPA*, 597 U.S. 697, 727 (2022). They are emission limits "based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly," and "technology-based standard[s]" focused on "improving the emissions performance of individual sources." *Id.* at 725, 726-27.

Section 111 provides clear congressional authorization for the Rule's traditional, technology-based standards. Congress reinforced that authority in the

2022 Inflation Reduction Act, directing EPA to assess power sector emissions expected from ongoing trends and the law's tax credits, and to use "the existing authorities of [the Clean Air Act]" to "ensure" power plant carbon emission reductions. 42 U.S.C. § 7435(a)(5)-(6) (Inflation Reduction Act, Pub. L. 117-169, § 60107 (2022)). The Rule follows this directive.

Movants nonetheless claim the Rule poses a "major question." *E.g.*, WV Mot. 13-16. Wrongly asserting that the Rule sets "impossible-to-meet standards," they argue the Rule is "generation shifting" in disguise. *See id.* at 15-16. As explained above, these "impossibility" claims fail because EPA's standard is based on technology that is both adequately demonstrated and achievable. Without the impossibility predicate, Movants' "major question" claim collapses.

Movants also accuse EPA of attempting to "get around" the holding of *West Virginia*, claiming the agency "knows" its standards cannot be met—thus calling into question EPA's good faith. WV Mot. at 1, 14. But they have failed to show any bad faith, much less the "strong" showing required to look into an agency's motives. *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 420 (1971).

Movants argue that traditional, technology-based standards still pose a major question because they supposedly have the same *effect* as the Clean Power Plan, shifting generation away from coal. WV Mot. 15-16, NRECA Mot. 15, NMA Mot. 10. But *West Virginia* already rejected this argument, finding "an obvious

difference" between a technology-based rule that has the effect of causing "an incidental loss" of market share, and the Clean Power Plan, which "announc[ed] what the market share of coal, natural gas, wind, and solar must be." 597 U.S. at 731 n.4. That some plant operators may choose to retire coal units rather than retrofit to meet the standards does not render the standards beyond EPA's authority. Moreover, as described more fully below, most changes in the composition of the electric generating fleet will be driven by underlying market trends and tax credits—not the Rule. *See* 89 Fed. Reg. at 39,876, 39,900.

II. Movants have not demonstrated irreparable harm

"This court has set a high standard for irreparable injury." *Chaplaincy of Full Gospel Churches v. England*, 454 F.3d 290, 297 (D.C. Cir. 2006). The asserted injury must be "both certain and great" and "of such *imminence* that there is a 'clear and present' need for equitable relief to prevent irreparable harm." *Id.* (quoting *Wisc. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985)). Where a claimed harm is financial, unrecoverable losses are irreparable only if they are "great," *Wisc. Gas*, 758 F.2d at 674, or "significant," *Air Transp. Ass'n of Am., Inc. v. Exp.-Imp. Bank of the U.S.*, 840 F. Supp. 2d 327, 335-36 (D.D.C. 2012). *See also Penn. v. DeVos*, 480 F. Supp. 3d 47, 67–68 (D.D.C. 2020) (allegations of harm from compliance costs "not sufficiently significant to warrant injunctive

relief"); *cf. Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 556 (D.C. Cir. 2015) (lack of irreparable harm where impact was likely "*de minimis* or zero").

As explained below, all of Movants' alleged harms from the Rule are insignificant, speculative and non-imminent, or both.

A. State compliance costs due to the Rule are routine and minimal

State Movants have not met the "high standard" of showing costs that are imminent and "both certain and great." *Chaplaincy*, 454 F.3d at 297. They claim they will be irreparably harmed by planning processes that "must" begin "immediately" and involve "significant resources." Ohio Mot. 22-23; WV Mot. 19-20. The state plan process envisioned by this Rule, however, is no more complex than states have conducted under the Clean Air Act for decades. *See* Seligman Decl. ¶¶ 13, 17; Bast Decl. ¶ 8. State Respondent-Intervenors extensively demonstrate the inadequacy of State Movants' irreparable harm claims in their opposition papers.

Further, even if state planning costs under the Rule *were* significant, no state is required to participate. States may decline to develop a plan, as many State Movants have done for past Section 111(d) regulations. *See, e.g.*, 85 Fed. Reg. 14,474, 14,476 tbl.2 (Mar. 12, 2020) (listing 42 states/territories that did not submit state plans, including all but three of Movant States). In that circumstance, EPA must develop a federal plan. 89 Fed. Reg. at 40,000; 40 C.F.R. § 60.5720b(a); *see*

also 86 Fed. Reg. 27,756, 27,758 tbl.2 (May 21, 2021) (listing 39 states/territories subject to federal plan). States that opt out face no penalty under Section 111. *See* 85 Fed. Reg. at 14,475; *see* 40 C.F.R. § 60.5720b. State Movants' decision to spend resources developing plans is entirely their choice, and therefore does not meet the high burden for showing irreparable harm. *Cf. Safari Club Int'l v. Salazar*, 852 F. Supp. 2d 102, 123 (D.D.C. 2012) (law is "well-settled" that irreparable harm standard is not met "when the alleged harm is self-inflicted" (cleaned up)).

B. Near-term industry compliance costs are routine and minimal

Compliance costs for power plants during the litigation are neither "imminen[t]" nor "great." *Mexichem*, 787 F.3d at 555. As discussed below, EPA reasonably concluded that the only activity an operator intending to install CCS might undertake during the next one to two years is a routine exercise of assessing project feasibility. Similarly, if a regulated source chooses to retire a unit rather than retrofit, the only near-term requirement is a planning and feasibility assessment. Such assessments are part of regularly conducted integrated resource plans. The costs are not "great," *Wisc. Gas*, 758 F.2d at 674, and most would have been incurred without the Rule, *see Mexichem*, 787 F.3d at 556. They are not harm justifying the "extraordinary remedy" of a stay. *Winter*, 555 U.S. at 22.

1. Major retrofit costs do not begin immediately

EPA reviewed current and past carbon capture project timelines and developed a representative timeline to meet a 2032 compliance deadline. Coal TSD 45-47. Phases of the project include feasibility studies, engineering, permitting, and construction. *See id.* at 43. Costs are modest at first, and slowly escalate in later phases. The first phase, a feasibility study, involves conceptual design, a preliminary technical evaluation, and screening of available capture technologies and vendors. *Id.* at 44. This is a routine exercise to determine which controls and standards should be incorporated into the state plan; it costs "substantially less than other components of the project." 89 Fed. Reg. at 39,874; *see also* Rochelle Decl. ¶ 32 ("less than 0.1% of total project costs"). It can also be completed in as few as six months and is the only work that will need to occur during the next two years. 89 Fed. Reg. at 39,874; Coal TSD at 48 tbl.7; *see also* Hovorka Decl. ¶ 33 and Grove Decl. ¶ 27 (storage and pipeline feasibility planning need not begin until 2026). Many plants have already conducted this initial analysis. Coal TSD at 44 n.100; Rochelle Decl. ¶ 40.

Citing past projects that unfolded over longer timelines, Movants claim they must start significant work on CCS projects immediately to meet EPA's deadline. *See, e.g.*, NRECA Mot. 11. But these longer historical examples are inapposite: those projects were conducted voluntarily, without regulatory requirements or

deadlines. Coal TSD at 43-44. And even then, construction timelines for the two most relevant historical projects—Boundary Dam and Petra Nova—are consistent with EPA's timeline. 89 Fed. Reg at 39,875. In short, the Rule provides plenty of time for project installation, without need for capital expenditures during this litigation.

2. Choosing retirement involves minimal planning costs

Movants protest that the Rule will force "premature[]" retirement of coal-fired units, stranding investments and scuttling inexpensive electric generation. *See* NRECA Mot. 3, WV Mot. 18. But as explained below, Movants have not shown that such retirements are attributable to the Rule or that planning for retirement during the pendency of litigation would involve more than feasibility studies.

Movants have failed to show that any anticipated coal-fired plant retirements will "directly result from" the Rule rather than existing market forces. *See Wisc. Gas*, 758 F.2d at 674. Movants portray a future in which all existing coal plants that have not already announced retirement will operate indefinitely. But due to the age and marginal economics of these units, coal-fired power plants have already been exiting the fleet in droves, a trend that is forecast to accelerate with or without the Rule. Power Sector Trends TSD at 23-24 & fig.11 (projections that "exclude the Final Rule"); *see also* Celebi Decl. ¶¶ 7-8; O'Connell Decl. ¶¶ 6, 10-11; Tierney Decl. ¶ 20. Coal-fired units face higher operating costs relative to other

generation, given older equipment, more expensive fuel, and state clean energy requirements. Celebi Decl. ¶¶ 9-14; O'Connell Decl. ¶¶ 7-9; Tierney Decl. ¶ 25. Thus, "premature" retirements are hardly a "certain" outcome of the Rule. And the marginal economics of coal-fired plants means any harm from some additional retirements cannot be "great." Celebi Decl. ¶¶ 4, 9-13 (discussing economic headwinds for coal plants).

Nor would Movants suffer "great" harm during this litigation by beginning to plan for new generation to replace retiring coal. *Contra* NRECA Mot. 19-21; EGST Mot. 16-18; EEI Mot. 21. Planning for future generation, including assessing the feasibility of specific projects, is a routine practice involving "minimal costs" that is always ongoing. O'Connell Decl. ¶¶ 13, 15-17; Tierney Decl. ¶¶ 23-24; Navarro Decl. ¶ 9. Near-term costs would be limited to design and site studies, or exploration of procurement from other generators. *See* O'Connell Decl. ¶¶ 30-36.

Movants assert that they could not undo early compliance choices if the Rule is later overturned. *See, e.g.*, WV Mot. 18; EEI Mot. 19. But coal retirement decisions can be reversed if those plants are later needed to meet demand. Tierney Decl. ¶ 41-42. And the Rule provides several opportunities for compliance deadline extensions if needed for grid reliability. 89 Fed. Reg. at 40,013-14.

Finally, Movants fail to substantiate their assertions that near-term planning to comply with the Rule would lead to an unreliable grid. NRECA Mot. 19; WV Mot. 16-17; EGST Mot. 26-27. Reliability authorities and utilities are already deep in the planning process for the longer-term transition to a cleaner, more reliable, and cheaper generation mix, with or without the Rule. Celebi Decl. ¶ 17; O'Connell Decl. ¶¶ 31-33, 35-36, 51-53; Tierney Decl. ¶¶ 22, 28. This will provide ample capacity and enhance operational reliability as compared to the disruptions to electric service that have increasingly marked the fossil-heavy, climate-buffeted grid of the recent past. Tierney Decl. ¶¶ 22, 28-29; *see also* Celebi Decl. ¶ 16; O'Connell Decl. ¶¶ 25-26, 38, 41-42, 45-47. As explained above, because the Rule only covers a small and shrinking portion of the fleet, it will not meaningfully affect the grid's overall resource adequacy—much less during this litigation.

III. A stay would harm Respondent-Intervenors and the public interest

The third and fourth stay factors weigh strongly against issuance of a stay. *See In re NTE Conn., LLC*, 26 F.4th 980, 991 (D.C. Cir. 2022) (final considerations include whether a stay "will substantially injure the other parties" and "where the public interest lies" (quoting *Nken*, 556 U.S. at 434)). If staying the Rule would delay its performance standard deadlines, as Movants assume, that would significantly harm Respondent-Intervenors and the public interest by leading to irreversible emissions of climate- and health-harming pollution.

Fossil fuel-fired power plants are the nation's largest stationary source of greenhouse gas emissions, responsible for 25 percent of the U.S. total in 2021. 89 Fed. Reg. at 39,799. These emissions steadily increase atmospheric concentrations of greenhouse gases, which are overheating the atmosphere and leading to more frequent and intense heat waves, increased ground-level ozone pollution, more intense hurricanes and other extreme weather events, rising seas, storm surges and flooding in coastal areas, and more intense and larger wildfires. *Id.* at 39,807-10.

Movants falsely suggest that delaying the Rule would sacrifice no public health or environmental benefit because the power sector is already reducing carbon emissions. EEI Mot. 22; WV Mot. 20. But the Rule will reduce carbon emissions by another almost 1.4 billion metric tons between 2028 and 2047. 89 Fed. Reg. at 40,004. In 2035 alone, EPA estimates the Rule will reduce emissions by 123 million metric tons. *Id.* at 40,005 tbl.4.

Movants also suggest that staying the Rule during litigation will have no emissions or climate impacts because compliance deadlines are years away. WV Mot. 20-21. That claim is inconsistent with Movants' own arguments: if they claim that compliance work is needed now to meet the Rule's deadlines, and the purpose of the stay is to delay that work, a stay would mean they will *not* meet the Rule's present deadlines. While Respondent-Intervenors do not concede that a stay would toll the Rule's compliance deadlines, it is clearly Movants' goal to avoid

implementing the standards for as long as possible, *see* WV Mot. 18-19; EEI Mot. 21, thereby depriving the public of the benefits of timely implementation.

Movants disingenuously claim that "a difference of 2-3 years in implementation due to a stay will not result in any measurable effect." EGST Mot. 29. But a stay that delays compliance deadlines will also delay the Rule's emission reductions, meaning hundreds of millions of additional tons of carbon will be irretrievably dumped into the atmosphere due to those years of delay. Carbon dioxide accumulations will be higher every year thereafter relative to what they would have been with the Rule, because such gases build up in the atmosphere. *See* 89 Fed. Reg. at 39,808. Thus every additional day of uncontrolled carbon pollution now increases the likelihood of catastrophic effects later. *See id.* Respondent-Intervenors' members are already suffering harms from climate change, *e.g.*, Mot. to Intervene, Jeffrey Decl. ¶¶ 4-15, ECF No. 2054080 (May 13, 2024), and those will only increase if the Rule's compliance deadlines are extended.

CONCLUSION

The Court should deny Movants' request to stay the Rule.

DATED: June 11, 2024

Respectfully submitted,

/s/ *Francis W. Sturges, Jr.*
(with consent)
Francis W. Sturges, Jr.
Alan Masinter
Ann B. Weeks
Clean Air Task Force

/s/ *Catherine Marlantes Rahm*
Catherine Marlantes Rahm
Natural Resources Defense Council
40 West 20th Street
New York, NY 10011
(212) 727-4628

114 State Street, 6th Floor
Boston, MA 02109
(617) 624-0234
fsturges@catf.us

Counsel for American Lung Association, Clean Air Council, American Public Health Association, and Clean Wisconsin

James Patrick Duffy
Center for Applied Environmental Law and Policy
6218 Georgia Avenue NW, Ste 1-538
Washington, DC 20011
(802) 233-7967
jay.duffy@caelp.org

Counsel for Natural Resources Defense Council

crahm@nrdc.org

Jaclyn H. Prange
Natural Resources Defense Council
111 Sutter Street, 21st Floor
San Francisco, CA 94104
(415) 875-6100
jprange@nrdc.org

David Doniger
Meredith J. Hankins*
Natural Resources Defense Council
1152 15th Street NW, Suite 300
Washington, DC 20005
(202) 321-3435
ddoniger@nrdc.org
mhankins@nrdc.org

**Admitted to practice in California, acting under the supervision of a member of the D.C. Bar.*

Counsel for Natural Resources Defense Council

CERTIFICATE OF COMPLIANCE

I hereby certify that the foregoing contains 5,096 words, excluding the items listed in Fed. R. App. P. 32(f), and was composed in Times New Roman font, 14-point. The motion complies with applicable type-volume and typeface requirements. Fed. R. App. P. 32(a)(5)-(6); Fed. R. App. P. 27(d)(2).

DATED: June 11, 2024

/s/ *Catherine Marlantes Rahm*

Catherine Marlantes Rahm
Natural Resources Defense Council

TABLE OF ATTACHMENTS

DECLARATION OF CHRISTOPHER T. BAST IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

I, Christopher T. Bast, declare as follows:

1. I submit this declaration in support of Intervenors' opposition to the motions to stay the Environmental Protection Agency's final rule entitled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 8, 2024) (Rule).

<u>Background and qualifications</u>

2. I am a climate change, clean energy, and decarbonization policy expert with two decades of experience in state and local government, non-profit policy advocacy, and private sector climate and clean energy consulting. My experience includes over eight years of service to the Commonwealth of Virginia in various appointed and classified roles across the administrations of four Democratic and Republican Governors. This experience includes working in the Office of the Governor as well as three different state agencies, including the

Virginia Department of Environmental Quality (VDEQ) and the Virginia Department of Mines, Minerals, and Energy (now Virginia Energy).

3. From 2018 until 2022, I served as the Chief Deputy Director of VDEQ. My responsibilities included advising the Governor, the Secretary of Natural and Historic Resources, and the VDEQ Director and Leadership Team on climate change, clean energy, and environmental justice issues. I worked directly with VDEQ staff to design and implement policy and various regulatory and non-regulatory approaches to reducing greenhouse gas emissions and improving public health and the environment. In this role, I led the work in support of the Governor's climate change portfolio, including development of the Virginia Carbon Rule, as well as development and implementation of the Virginia Clean Economy Act (VCEA), both of which facilitated Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI).

4. Though not a personnel manager, in my role as Chief Deputy Director, I directed VDEQ Air Division staff in the implementation of VDEQ and Governor's Office priority issues – including in rulemakings such as that which established the Virginia Carbon Rule, the Renewable Energy Permit By Rule, and the Advanced Clean Cars Program. I also

advised VDEQ staff, the Governor, and the Secretary on implications related to the VCEA, other clean energy policy issues, and air and water permit applications that came before VDEQ and the relevant state Boards. As the Governor's appointed Chief Deputy Director, I facilitated Virginia's entry and participation in RGGI and I participated in policymaker deliberations on this topic with the General Assembly, the Office of the Governor, and the Office of the Attorney General. I also worked closely with VDEQ Air Division staff and air regulators from other states on RGGI and other issues regarding regional cooperation in the implementation of state Clean Air Act Authority and other climate pollution reduction initiatives.

5. In the course of my professional career, I have participated in the development of state plans in response to EPA regulations and Virginia law. I have worked directly with VDEQ's Air Division on state implementation of EPA standards, implementation of the Virginia Carbon Rule to meet participation requirements for RGGI, and implementation of Virginia climate and energy legislation such as the Virginia Clean Economy Act.

6. In preparing this Declaration, I have reviewed the Rule; various EPA guidance documents related to the Rule's implementation; the Motion to Stay filed by Petitioners State of West Virginia, *et al.* ("Petitioners"); the Declarations of Michael G. Dowd and Glenn Davis (collectively, "Virginia Government Declarants"); the 2022 Virginia Energy Plan; and various articles and thought leadership pieces on the Rule published by advocacy organizations and academic institutions.

7. Based on my former role as Chief Deputy Director of the VDEQ, my career as an energy and climate expert, and my review of the relevant materials, I have the personal knowledge and experience to understand the energy and environmental regulatory process in the Commonwealth of Virginia and what steps VDEQ will need to undertake to implement the Rule, including preparation of a state plan.

Compliance Requirements

8. Based on my professional experience, the Rule's state planning requirements and timeline are reasonable. These rules are no more difficult than other federal and state regulations with which the state regularly complies. This is especially true considering that the Rule will apply to just two coal-fired power plants in Virginia.

9. Notably, the Virginia Government Declarants make no claims of hardship from the Rule's state planning process requirements, which aligns with my opinion that the Rule's state planning requirements will not be a burden for VDEQ.

10. The Virginia Government Declarants' main issue with the state planning timeline is that the two-year time frame for developing a state plan for just two affected power plants will leave little time for innovative solutions due to the Rule's requirement that state plan development include meaningful public outreach and consideration of environmental justice concerns.

11. The meaningful outreach requirements are nothing new in Virginia. VDEQ staff know how to conduct outreach within the Rule's state planning timeline, as these types of considerations have been required by Virginia's Environmental Justice Act for over four years.[1] Public outreach and environmental justice considerations are already an integral part of VDEQ's rulemaking process. Thus, VDEQ already has

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[1] Va. Code § 2.2-235 (2020) ("It is the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth, with a focus on environmental justice communities and fenceline communities.")

ample experience with the type of outreach required by the Rule. Considerations of environmental justice are not tangential to a project and Virginia's Environmental Justice Act ensures its consideration. During my time at VDEQ, and in the time both preceding and succeeding my tenure, the agency has not shied away from sensitive permitting issues because of environmental justice.

12. Rather than being a burden, I find that in general, stakeholder engagement is a catalyst for innovative solutions to environmental regulations, as impacted stakeholders often have valuable input into the process for regulatory development and implementation.

13. Virginia Government Declarants claim that the Rule is "a piecemeal approach to controlling carbon pollution in Virginia" and that the VCEA presents a comprehensive approach to controlling emissions from the electric power sector in Virginia. In my experience, state initiatives have always incorporated federal requirements and the regulatory certainty provided by the Rule will help Virginia achieve state emission reduction goals.

Conclusion

14. It is the legal responsibility of VDEQ to protect and enhance the environment of Virginia and to address climate change by implementing policy and regulatory approaches to reducing climate pollution. It is also the legal responsibility of VDEQ to further environmental justice.[2] Based on my experience as Chief Deputy Director of VDEQ and as a policy advisor to the previous Virginia Governor, VDEQ is well situated to complete the state planning process with minimal costs and within the prescribed timeline, similar to how the agency has for numerous past rules.

I, Christopher T. Bast, declare under penalty of perjury that the foregoing is true and correct.

Executed this 9th day of June, 2024.

CBast

[2] Va. Code §10.1-1183(B)(2020) ("It is the policy of the Department of Environmental Quality to protect and enhance the environment of Virginia… The purposes of the Department are… [t]o address climate by developing and implementing policy and regulatory approaches to reducing climate pollution… and.. ensuring that climate impacts…are taken in account across all programs and permitting processes…to further environmental justice and enhance public participation in the regulatory and permitting processes.").

DECLARATION of METIN CELEBI, PH.D.

I, Dr. Metin Celebi, declare:

1. I am a Principal at The Brattle Group, a global economic consultancy. I hold a Ph.D. in Economics from Boston College and have over 20 years of experience in the U.S. electric sector. A copy of my resume is provided in Attachment A.

2. Based on my review of the U.S. Environmental Protection Agency's ("EPA") final rulemaking titled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" and published at 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule," "GHG Rule," or "Rule") and various supporting materials and public comments in the docket for that rulemaking, Docket ID No. EPA-HQ-OAR-2023-0072, I offer the following expert opinions on the economics of coal-fired electric generating units ("EGUs") in the U.S. and the Rule's potential impacts on the U.S. coal fleet.

3. My opinions as expressed in this Declaration are informed by my training and extensive experience as an energy economist. I have routinely conducted economic analyses of coal plant operations, environmental regulations, and long-range planning for electric utilities—issues that are central to this Rule. I have testified in cases before the Federal Energy Regulatory Commission ("FERC"), the U.S. District Court for the Eastern District of Missouri, the Public Service Commission of Wisconsin, Iowa Utilities Board, the Pennsylvania Public Utility Commission, the Kentucky Public Service Commission, the Public Utility Commission of Texas, and the Superior Court of the State of Arizona on topics including the economics of coal plant retirements and their impact on wholesale energy prices, economic damages in energy contract

disputes, locational marginal price spikes in the Pennsylvania-New Jersey-Maryland (known as "PJM") Regional Transmission Organization, allocation of certain ancillary services costs among market participants in the Electric Reliability Council of Texas (known as "ERCOT"), and wholesale power prices in Arizona. More recently, I filed a declaration before the Supreme Court of the United States concerning compliance requirements and options under the EPA's Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard.

4. Coal-fired power plants in the U.S. have been facing a challenging set of economic and policy drivers, including low gas prices and decreasing costs of renewable energy, rising operation and maintenance ("O&M") costs, and states' climate and clean energy policies as well as federal environmental regulations (apart from the Rule in question). These drivers have persisted over the past decade, if not longer, and they will likely continue in their trajectory in the foreseeable future. Together, these drivers have eroded the economic viability of coal plants across the country. While the EPA's Final Rule will likely accelerate the timing of retirement for some coal-fired EGUs, the majority of future coal retirements over the next 10–15 years will likely happen regardless of this Rule. Importantly, the Rule does not require the affected power plants to change their operations until 2030. My opinions are based on several observations below.

Continuing Decline in Coal Plants' Capacity and Utilization

5. As of March 2023, 86.8 GW of the 218 GW coal fleet was announced to retire by 2040.[1] In other words, approximately 40% of U.S. coal capacity was already slated to retire before this Rule was proposed.

[1] Hitachi Powergrid, Velocity Suite, as-of March 6, 2023. Based on nameplate capacity, as tracked by Hitachi Powergrid. There may be discrepancies between the estimated coal fleet sizes reported here and what is used by EPA for its regulatory impact analysis that are a result of using different definitions to determine the active fleet. Fleet estimates used herein are based on the retirement date (or lack thereof) of units as tracked by Hitachi.

6. More coal plants will almost certainly retire than just those that have already announced their intent to retire. In fact, announced retirements have historically understated the actual retirements by more than 50%.[2] For instance, as of March 2018, only about 14 GW of coal capacity was announced to retire between 2019 and 2022. In reality, more than 44.5 GW of coal capacity was retired over that period, more than three times the expectation.

7. The large number of recent announced coal plant retirements is a continuation of a long-running and accelerating trend of declining coal usage in the U.S. After a small, albeit steady, increase in the early aughts, the total U.S. operating coal capacity began to decrease at a rapid pace in the early 2010s. By the end of 2023, there was 209 GW of coal capacity in the U.S., a decline of 35% over the past 18 years. Concurrently, the amount of electricity generated from coal plants also declined substantially: annual generation fell from 2,013 TWh in 2005 to 675 TWh in 2023, a greater than 65% decline. The fleet-wide capacity factor, a measurement of how fully power plants are operated, decreased from 67% to 38% over the same time period.[3] Not only has the U.S. coal fleet been reduced in size, it has also generated significantly less electricity both on a fleet-wide basis and a per-plant basis.

8. Recent analysis and reports anticipate that the decline in coal usage will continue well into the foreseeable future, with most U.S. coal plants expected to retire by 2040. For example, in the EPA's regulatory impact analysis of the Rule, only about 23% of current coal-fired plant capacity (or 42 GW out of 181 GW) is forecast to be online by 2040 under the business-as-usual scenario (i.e., baseline case without the GHG Rule).[4]

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[2] Celebi et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.
[3] Capacity factors were calculated using the net annual generation divided by the nameplate capacity multiplied by 8760 hours. Annual generation totals are based on data aggregated by Hitachi Powergrid, Velocity Suite,
[4] EPA, Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable

INCREASING COMPETITIVE PRESSURE AND RISING COSTS FOR COAL PLANTS

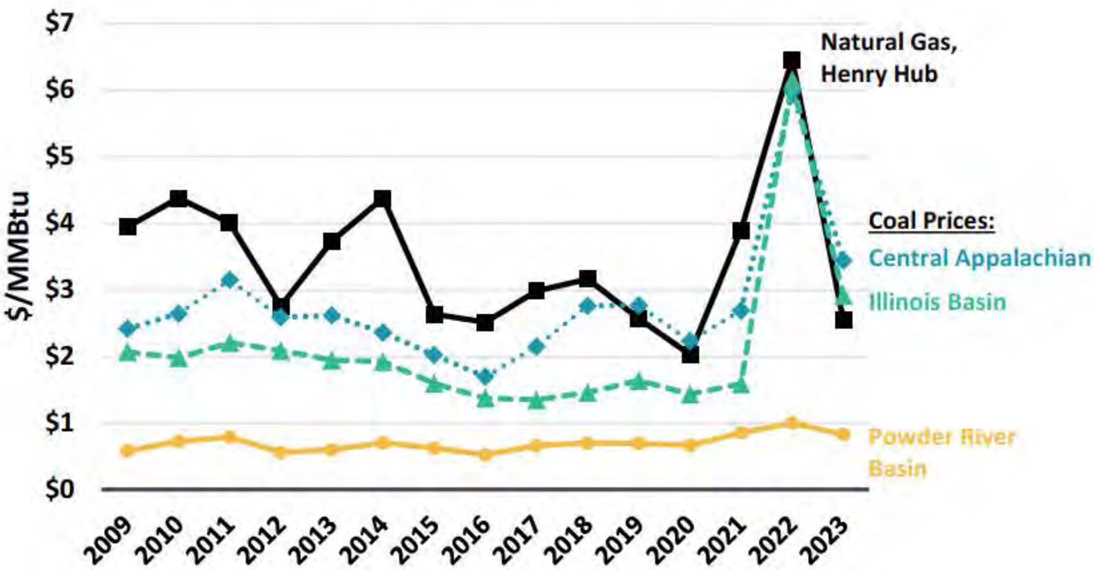
9. Low natural gas prices are a primary factor behind the U.S. coal plants' decline in economic competitiveness. In addition to making it cheaper to replace generation output of retiring coal-fired units, low gas prices also reduce wholesale power prices, undermining the profitability of coal plants. Indeed, the successful deployment of shale gas technology is the largest single factor responsible for lower wholesale power prices in the U.S.[5] As seen in Figure 1 below, gas prices over the 2009 to 2023 period experienced a sustained and substantial decline. Annual average spot prices at Henry Hub, a major gas trading hub in the U.S., over this period decreased from about \$3.94/MMBtu to \$2.54/MMBtu (in nominal dollars). Gas prices increased sharply during the occasional cold snaps, when demand for gas spiked, but mostly trended downward. Gas price forecasts remained elevated for some time as industry analysts were unsure about the permanent nature of low gas prices, but as the impacts of shale gas on the market became clearer, forecasts were revised downward.[6] In 2021 and 2022, increased LNG exports, Russia's invasion of Ukraine, and recovery from the pandemic drove gas prices higher, but the market has since adjusted to these shocks and appeared to stabilize. In contrast, annual average coal prices have increased over the last 14 years, from 2009 to 2023 (see Figure 1 below).

Clean Energy Rule ("RIA"), April 2024, at P. 3-20 and Table 3-14. Different data sources report different capacities for the total fleet size in the U.S. For consistency, the fleet-wide metrics are based on data collected by Hitachi Powergrid, Velocity Suite, unless otherwise specified.

[5] A. D. Mills, D. Millstein, R. Wiser, J. Seel, J. p. Carvallo, S. Jeong, W. Gorman, Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017, Lawrence Berkeley National Laboratory, November 2019.

[6] Celebi et al., A Review of Coal-Fired Electricity Generation in the U.S., The Brattle Group, April 27, 2023.

Figure 1: Historical Coal Spot Prices versus Henry Hub Natural Gas Prices



Source: S&P Global Market Intelligence[7]

10. As gas prices have decreased, so too have the costs of new renewables and battery storage, making it more economic to deploy these technologies (see Figure 2A and Figure 2B). The greater level of renewable energy and battery storage deployment in many parts of the country in recent years further diminished the economic attractiveness of coal plants. Renewable energy resources with zero short-run marginal costs have similar effects on coal plants as cheap natural gas, pushing additional lower cost generation resources below the dispatch costs of coal units, hence reducing the wholesale power prices and the profit margins of coal-fired units. The

[7] S&P Global Market Intelligence requires the following disclaimer to accompany presentations reflecting its services: "Reproduction of any information, data or material, including ratings ("Content") in any form is prohibited except with the prior written permission of the relevant party. Such party, its affiliates and suppliers ("Content Providers") do not guarantee the accuracy, adequacy, completeness, timeliness or availability of any Content and are not responsible for any errors or omissions (negligent or otherwise), regardless of the cause, or for the results obtained from the use of such Content. In no event shall Content Providers be liable for any damages, costs, expenses, legal fees, or losses (including lost income or lost profit and opportunity costs) in connection with any use of the Content. A reference to a particular investment or security, a rating or any observation concerning an investment that is part of the Content is not a recommendation to buy, sell or hold such investments or security, does not address the suitability of an investment or security and should be relied on as investment advice. Credit ratings are statements of opinions and are not statements of fact."

combined effects of renewables and low-cost natural gas can lead to coal plants not being selected to serve load (and earn revenue) in many hours.

Figure 2A: Historical Solar and Wind Levelized Costs and Contract Prices

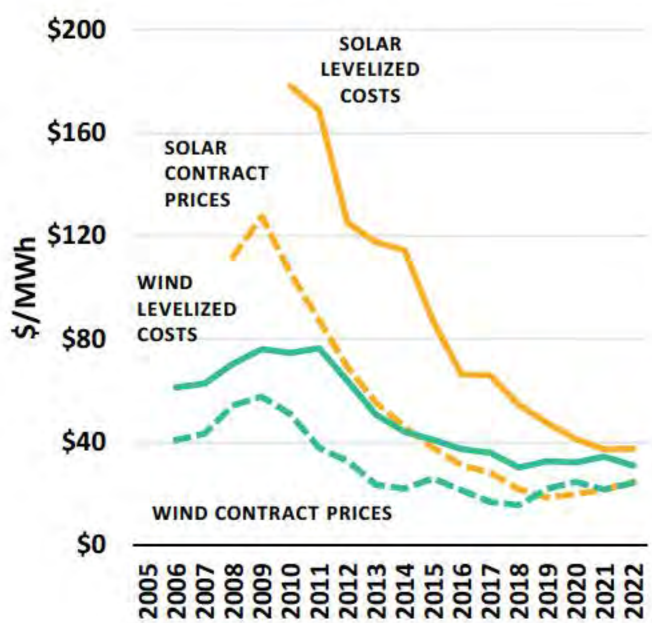
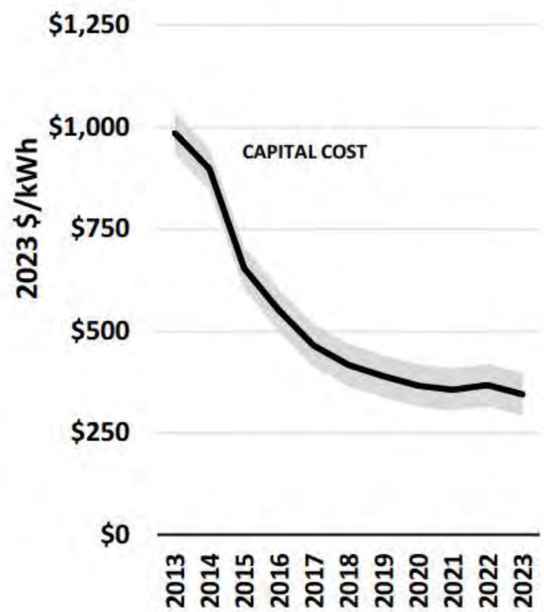


Figure 2B: Historical Cost Decline of Utility-Scale Battery Storage Facilities



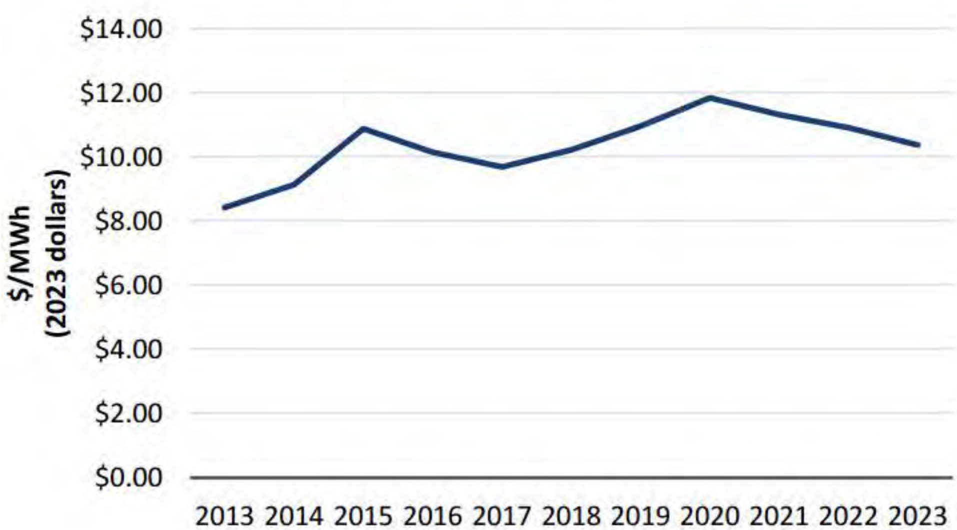
Notes and Sources:

- Wind and Solar: Brattle, Bulk System Reliability for Tomorrow's Grid, 2023, Figure 2. Costs expressed in nominal dollars.
- Storage: Brattle, Bulk System Reliability for Tomorrow's Grid, 2023, Figure 3. Shaded portion corresponds to a 25% low and high range on the non-pack costs of battery storage systems.

11. As U.S. coal plant owners struggle with the competitive pressure from cheap natural gas price and low-cost renewable energy and battery storage resources, they also have to grapple with rising costs to operate an aging coal fleet. On average, non-fuel O&M of the coal fleet operating in 2023 and owned by regulated utilities (investor-owned, municipal, and cooperative utilities) have increased in real 2023 dollars from $8.45/MWh in 2013 to $10.53/MWh in 2023 (see Figure 3 below). As coal units become older, they are more prone to outage and require more maintenance. Older plants tend to experience more frequent cycling, higher equipment failure rates, and therefore greater maintenance costs relative to the amount of power

generated and sold. Indeed, each additional year of an average coal unit's life corresponds to an additional $0.13/MWh of O&M costs.[8] Aging plants also require more capital investments: each additional year of a coal plant's life corresponds to an additional $0.04/MWh of annual capital expenses.[9] Non-fuel O&M costs will likely increase as the U.S. coal fleet becomes older. And the average age of the U.S. coal fleet is already higher than at any given point in the history of the coal fleet: the average age of the current operating fleet is 45.7 years, nearly 25% older than the fleet in 2005.

Figure 3: Historical Non-Fuel O&M Costs of U.S. Regulated Coal Plants



12. Competitive pressure from natural gas, renewable energy, and energy storage coupled with high O&M costs for operating the coal-fired plants means that many coal power plants are earning less from energy, capacity, and ancillary services revenue than their avoidable costs. For instance, in PJM, only 2% of coal-fired units fully recovered their avoidable costs in 2023 from all markets, compared to 83% of coal-fired units in 2014.[10] Unlike the remainder of

[8] These cost estimates are reported in 2017 dollars and reflect incremental costs for each year of a plant's age beyond a base total O&M cost of $5.44 per MWh. U.S. Energy Information Administration, Generating Unit Annual Capital and Life Extension Costs Analysis, 2019, p. 9.
[9] *Id.*
[10] 2023 State of the Market Report for PJM, Monitoring Analytics, 2024, p. 415.

the generating fleet (including natural gas plants, solar, wind, etc.), coal units are often unable to recover enough of their avoidable costs through the capacity market. The dark spread, a measurement of difference between market price and the cost of coal used to generate power, decreased across PJM hubs by 90% between 2014 and 2023, indicative of the current low profit margins that coal plants are facing.[11]

13. How these dynamics play out can be observed at the plant level as well. For individual coal plants, these factors can impact the frequency of their operation. For example, the capacity factor of the New Madrid power plant, a 52-year-old coal plant located in Missouri, decreased from 66% in 2019 to 45% in 2023. Over the same period, its estimated total non-fuel O&M costs increased on a dollar per MWh basis by approximately 50%, while nearby wholesale power prices have increased less, by approximately 15%.[12] Similarly, Antelope Valley power plant, a 40-year-old coal plant in North Dakota that operates in Southwest Power Pool (SPP), saw its capacity factor drop from 77% in 2019 to 63% in 2023. Its estimated total non-fuel O&M costs per MWh increased by 31% over the same period, while regional market prices increased less, by 19%.[13]

Many Coal Plants Have to Comply with States' Climate and Clean Energy Policies

14. Many states have stringent targets to reduce GHG emissions and increase reliance on clean energy. Currently, 24.9 GW of the currently operating coal units that have not yet

[11] 2023 State of the Market Report for PJM, Monitoring Analytics 2023; PJM, 2020 State of the Market Report for PJM, Monitoring Analytics, 2021.

[12] Wholesale price increase reflects increase in On-Peak, Day-Ahead prices between 2019 and 2023 at the MISO Arkansas hub. State of the Market Report 2020, Southwest Power Pool, August 12, 2021, p. 131; State of the Market Report 2023, Southwest Power Pool, May 20, 2024, p. 140.

[13] *Id.,* reflects increase in On-Peak, Day-Ahead prices between 2019 and 2023 at the SPP South hub, located in central Oklahoma. The New Madrid and Antelope Valley power plants have both been explicitly named in the motion for stay by National Rural Electric Cooperative Association.

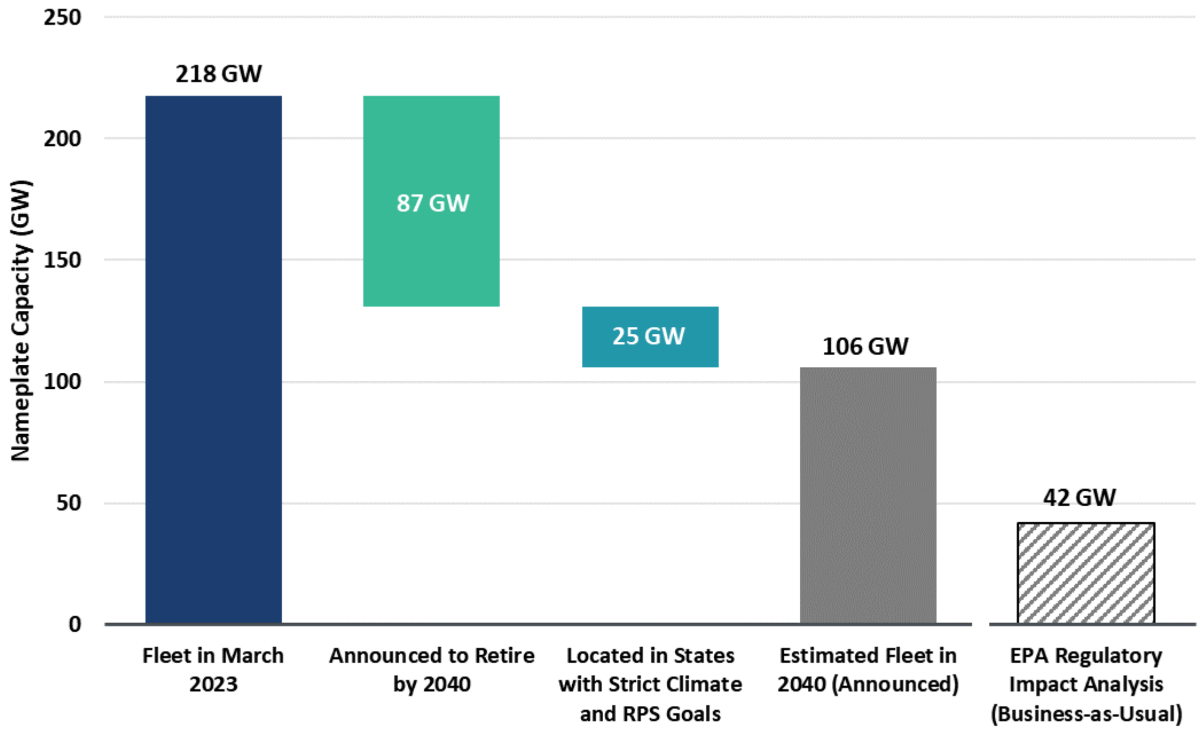
announced to retire by 2040 are in states that have aggressive decarbonization goals or mandates.[14] To comply with these clean energy and decarbonization requirements, coal plant owners will likely need to retire their coal assets or install CCS equipment before 2050. (They can also reduce GHG emissions from other power plants in their portfolio, but doing so would not be economic if the variable costs to operate coal EGUs are higher.) Compliance with other federal regulations will further add costs to operating coal plants.[15]

15. In summary, even without the EPA's Final Rule on GHG emissions from existing coal-fired units, more than half of the coal fleet capacity as of March 2023 was either already slated for retirement by 2040 or located in states with strict decarbonization and RPS goals (see Figure 4). As explained above, the announced retirements are likely an understatement of the actual retirements by 2040, even without the GHG rule.

[14] States with aggressive decarbonization goals or mandates (i.e., states with 100% clean energy targets; 100% greenhouse gas emissions reduction targets relative to an established baseline; or net zero greenhouse gas emissions targets) with greater than 100 MW of active coal capacity include Colorado, Delaware, Illinois, Louisiana, Maryland, Michigan, Minnesota, Nevada, New Mexico, New York, North Carolina, Virginia, Washington, and Wisconsin.

[15] These federal regulations include the Effluent Limitations Guidelines and Standards, Mercury and Air Toxics Standards, Good Neighbor Plan, Regional Haze Rule, and Coal Combustion Residual Rule, among others.

Figure 4: U.S. Coal-fired Generation Fleet Outlook without the EPA GHG Rule



Ongoing Efforts to Plan for Load Growth and an Orderly Transition

16. The recently emerging load growth is unlikely to improve the long-term economic viability of coal plants. After decades of persistently low load growth, the U.S. power sector is entering a period of expansion. Data centers supporting web-based services, artificial intelligence, and cryptocurrency mining, along with manufacturing facilities (including those used to produce hydrogen) and the electrification of the transportation and building sectors will increase demand for electricity in the coming years. However, the exact magnitude of these load drivers is unclear at this time, as is where they will take place. But even if significant load growth will materialize, the industry can serve new load with renewables energy resources, storage, and existing and new natural gas units. In fact, of the 1,570 GW of generation capacity waiting in the interconnection queues to be connected, clean energy projects such as wind and solar make up an overwhelming

majority (~1,480 GW).[16] In addition, over 1,000 GW of storage capacity is in the queues. While only a fraction of the resources in the queues eventually will be built and connected to the grid, this snapshot indicates that a large portion of anticipated new load growth can be met with clean energy resources. Ongoing efforts to shorten the time projects spend in the interconnection queues and to build out more transmission capacity will help bring these renewable resources online more speedily.[17] Further, the push to leverage demand-side resources such as energy efficiency and load flexibility will further reduce the need for more supply resources.[18,19]

17. An orderly transition away from coal can preserve grid reliability and do so at lower costs to customers. The transition introduces challenges but also offers abundant opportunities and solutions to address those challenges, shifting the focus of grid reliability management practices.[20] Irrespective of the EPA's GHG emissions regulations, a comprehensive suite of reliability reforms is needed to address the transition challenges. Elements of such reliability reforms are already in place or underway at various grid operators. Acceleration of these reforms should be a priority to ensure reliability during the transition. For specific cases in which EPA's

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[16] Joseph Rang et al., "Queued Up: 2024 Edition." Lawrence Berkeley National Laboratory, p. 3. https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

[17] See *Improvements to Generator Interconnection Procedures and Agreements,* Order No. 2023, 184 FERC 61,054 (2023), and *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation,* Order No. 1920, 187 FERC ¶ 61,068 (2024).

[18] According to a Brattle study, there is as much as 200 GW (20% of peak load) of cost-effective load flexibility potential in the U.S. by 2030. *See* Ryan Hledik, et al., "The National Potential for Load Flexibility: Value and Market Potential Through 2030." The Brattle Group. https://www.brattle.com/insights-events/publications/brattle-study-cost-effective-loadflexibility-can-reduce-costs-by-more-than-15-billion-annually/. A U.S. DOE report finds that demand-side resources can contribute to between 10-20% of peak demand. *See* Jennifer Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants," US Department of Energy. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.

[19] Mindful of these challenges, the EPA pushed back the compliance date for coal plants by two years and introduced options to extend the compliance deadline due to reliability concerns.

[20] Metin Celebi et al., "Bulk System Reliability for Tomorrow's Grid", The Brattle Group, December 20, 2023. https://www.brattle.com/wp-content/uploads/2023/12/Bulk-System-Reliability-for-Tomorrows-Grid_December-2023_Final.pdf.

GHG regulations result in transition-related challenges and reliability reforms do not keep pace, the Rule already allows for regulatory flexibility in addressing reliability needs.

18. Coal plants across the country have been under great economic pressure due to high operating costs, low natural gas and renewable energy costs, and state and federal regulations—economic and policy drivers that are independent of the Rule. These drivers are likely to persist in the foreseeable future, and the majority of anticipated coal plant retirements over the next decade are likely to occur irrespective of this Rule.

I declare that the above is true and accurate under the penalty of perjury.

Executed in Boston, Massachusetts on June 7, 2024.

Metin Celebi

Attachment A - Resume

Metin Celebi

PRINCIPAL

Practice Leader: Electricity Litigation & Regulatory Disputes

Boston +1.617.864.7900 Metin.Celebi@brattle.com

Dr. Celebi is an expert in electricity markets, resource planning, and the analysis of environmental and climate policy.

He has assisted clients in the areas of electricity litigation and regulatory disputes, including on the economic viability of coal-fired and nuclear power plants, wholesale power pricing, and market design. Dr. Celebi has also analyzed federal and state climate policies, environmental regulations, the role of hydrogen in reducing economy-wide greenhouse gas (GHG) emissions, generation plant valuation, and transmission cost allocation.

Dr. Celebi has provided expert testimony in a number of cases before the Supreme Court of the United States, district courts, and federal and state energy regulatory agencies. His testimonies have covered topics including the compliance burden of federal environmental regulations; economic damages in energy contract disputes; transmission cost allocation; excessive charges in long-term power contracts; causes of LMP spikes in PJM; and the allocation of ancillary services costs among market participants in ERCOT. He has also consulted and testified on matters related to coal plants, the recovery of undepreciated past investments, and the impact of coal plant retirements on wholesale energy prices.

AREAS OF EXPERTISE

- Electricity Litigation & Regulatory Disputes
- Electricity Wholesale Markets & Planning

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2000–Present)**
  Principal (2011–Present)
  Senior Associate (2006–2011)
  Associate (2000–2006)

- **London Economics, Inc. (1999–2000)**
  Associate
- **Boston College (1998–1999)**
  Teaching Fellow, Microeconomics and Macroeconomics

EDUCATION

- **Boston College**
  PhD in Economics
- **Bilkent University (Ankara, Turkey)**
  MA in Economics
- **Middle East Technical University (Ankara, Turkey)**
  BS in Industrial Engineering
- **Hebrew University**
  Summer School in Economic Theory on Auctions and Market Design

EXPERT TESTIMONY

- Before the Supreme Court of the United States, declaration on behalf of Public Interest Respondents re: compliance requirements and flexibility to choose among compliance options under the EPA's Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard (October 26, 2023).
- Before the Iowa Utilities Board, direct testimony on behalf of Interstate Power and Light Company re: reasonableness of IPL continuing to fully recover the remaining net book value of Lansing Generating Station Unit 4, a coal-fired generating unit, after the unit's retirement (October 12, 2023).
- Before the United States Court of Appeals for the Sixth Circuit, declaration on behalf of Conservation Groups re: compliance requirements and flexibility to choose among compliance options under the EPA's Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard (September 5, 2023).
- Before the United States Court of Appeals for the District of Columbia Circuit, declaration on behalf of Environmental and Public Health Intervenors re: compliance requirements and flexibility to choose among compliance options under the EPA's Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard (August 18, 2023).

- Before the District Court 165th Judicial District, Harris County, Texas, prepared expert report on behalf of Peaker Power, LLC re: economic damages from the counterparty's violation of heat rate call option contracts by exceeding the annual cap on exercise hours during Storm Uri in February 2021 (July 25, 2022).
- Before the Federal Energy Regulatory Commission (FERC), prepared answering testimony on behalf of Tri-State Generation and Transmission Association, Inc. re: the appropriate approach to determine the contract termination payment from a departing member (February 4, 2022, March 25, 2022).
- Before the United States District Court for the Western District of North Carolina Charlotte Division, direct and rebuttal expert reports on behalf of NTE Energy re: discounts provided by Duke Energy Progress (DEP) to City of Fayetteville in its wholesale power supply contract and the impacts on competition as well as on rates being charged to DEP's other wholesale and retail customers (January 14, 2022, February 18, 2022).
- Before the Public Service Commission of Wisconsin, prepared direct testimony on behalf of Wisconsin Power and Light Company re: appropriateness of WPL continuing to recover as a regulatory asset the undepreciated past investments at the Edgewater 5 coal unit after its proposed retirement in 2022 (May 27, 2021).
- Before Québec Régie de l'énergie, prepared direct testimony and oral testimony in hearing on behalf of Hydro-Québec Trans-Énergie (HQT) re: the adequacy of the categories used by HQT to classify its transmission investments and HQT's treatment of transmission losses in transmission planning (March 7, 2019).
- Before the Public Service Commission of Kentucky, prepared direct testimony on behalf of Big Rivers Electric Corporation re: economic viability of Station Two coal plant (May 1, 2018).
- Before the United States District Court Eastern District of Missouri Eastern Division, expert report on behalf of Ameren Missouri re: impacts of proposed mandates to install emission control equipment at Rush Island coal plant on revenue requirements and economic viability of the plant, Case No. 4:11 CV77 RWS (April 23, 2018 and April 27, 2018).
- Before the Superior Court of the State of Arizona, expert report on behalf of Vieste SPE, LLC and Vieste Energy LLC re: projected long-term wholesale power prices in Arizona (January 30, 2017 and February 21, 2017).
- Before the Federal Energy Regulatory Commission (FERC), prepared direct testimony on behalf of the California parties re: economic burden imposed by the prices in two long-term

contracts that the California Department of Water Resources (CDWR) signed with Shell and Iberdrola during the California energy crisis (May 19, 2015 and October 6, 2015).

- Before the Public Service Commission of Wisconsin, pre-filed rebuttal and surrebuttal testimony on behalf of Wisconsin Public Service Corporation re: the impacts of pending coal plant retirements and environmental retrofits on energy and capacity prices in the MISO market region (December 14, 2012 and January 11, 2013).
- Before the District of Columbia Office of Tax and Revenue, affidavit on behalf of Pepco Energy Services re: categorization of electricity as a tangible property versus a service for determining the eligibility of electricity sales for exemption from sales tax (July 15, 2011).
- Before the Pennsylvania Public Utilities Commission, Docket No. P 2008 2020257, rebuttal and surrebuttal testimony on behalf of Pennsylvania Electric Company re: causes and pricing of transmission congestion in Wellsboro area in PJM (January 16, 2009 and March 10, 2009) (with P. Hanser).
- Before the Public Utilities Commission of Texas, Docket 33416, affidavit supporting Constellation New Energy's request for expedited hearing re: allocation of replacement reserve costs in ERCOT (November 8, 2006).

SELECTED CONSULTING EXPERIENCE

ENERGY LITIGATION AND REGULATION

- For a coal producer, provided litigation support to estimate potential economic damages from an alleged breach in a long-term coal supply agreement.
- For the owner of two gas-fired peaking generation plants in Texas, provided expert testimony before the District Court 165th Judicial District, Harris County, Texas regarding a dispute in a heat rate call option (HRCO) contract with Shell Energy North America. Estimated economic damages from the counterparty's violation of the HRCO contracts by exceeding the annual cap on exercise hours during Storm Uri in February 2021, and assessed the economic value of the cancelation clause in the HRCOs.
- For Calpine, managed a team of consultants to support expert testimony in a bankruptcy court regarding ERCOT wholesale power prices during a February 2021 storm when extreme weather conditions caused nearly half of Texas to lose power for several days. The testimony from a Brattle expert explained why the high power prices were consistent with the scarcity pricing mechanism and market design in ERCOT, and such prices reflected, or even understated, the value of loss load during the scarcity conditions.
- For NTE Energy, provided expert testimony on discounts provided by Duke Energy Progress (DEP) to City of Fayetteville in North Carolina in its long-term wholesale power supply contract, and the resulting impacts on wholesale competition as well as on rates being charged to DEP's other wholesale and retail customers.
- For Tri-State Generation and Transmission Association, Inc., provided expert testimony before the FERC regarding the appropriate economic principles to determine the contract termination payment from a departing member.
- For a generation owner in ERCOT region, managed a team of consultants to prepare expert testimony and provide economic litigation support in a bankruptcy proceeding regarding the real-time energy prices during the winter Storm Uri in February 2021.
- For the owner of a paper mill in Minnesota, provided economic litigation support in an arbitration dispute regarding the pricing terms of a steam supply contract with an electric utility that operated a cogeneration facility.

- For a co-owner of a nuclear power plant project in the Southeast United States, evaluated the prudency of past decisions to start and continue construction until the project was eventually terminated. These investment decisions by the co-owners of the project were subject to multiple lawsuits regarding the appropriateness of recovering past investment costs from the utility's customers. Evaluated the ranges of long-term outlooks on major market fundamentals and project costs as of past decision points to assess the projected economics of continuing the project against options involving termination and replacement by other new resources.
- For the owner of a coal plant in the eastern United States, developed an expert testimony in an arbitration proceeding regarding a *force majeure* claim for non-performance in supplying a pre-determined volume of coal combustion byproducts under a long-term contract. Evaluated the drivers of the historical reductions in generation output and the accompanying byproducts, and the impacts of the drivers outside the control of the plant owner on the supply of byproducts under the contract.
- For Hydro-Québec Trans-Énergie (HQT), provided expert testimony before Québec Régie De l'énergie on the adequacy of the categories used by HQT to classify its transmission investments and HQT's treatment of transmission losses in transmission planning. Provided expert opinions before the regulator on the adequacy of HQT's investment categories in allocating the investment costs across different categories for multi-objective projects. Compared the HQT practices against those adopted by other system operators in the United States and Canada.
- For investors in refined coal production facilities in the United States, managed several consulting teams in supporting expert testimonies submitted before a United States Tax Court on the economic rationale and requirements behind the refined coal production tax credit, and on the operational and environmental permitting risks for the investors of refined coal production facilities.
- In an international arbitration dispute involving a coal mine in South America, co-managed a team to support expert report on the economic damages associated with a change in royalty structure. The analysis included the impact of royalty terms on the incentives for increasing mine production and on royalty payments to the government, under base outlook and sensitivities for projected international coal prices, mine cost structure, and discount rates.

- In a coal bankruptcy case regarding the qualification of a coal supply contract under the safe harbor provisions in the United States Bankruptcy Code, assisted an electric utility to evaluate the effectiveness of a long-term coal supply agreement as a hedge against regional fuel and power prices, including alternative coal prices and the more volatile prices of natural gas and wholesale power.
- In a large litigation case before the FERC, provided testimony on the economic burden imposed by the prices in two long-term contracts that the California Department of Water Resources (CDWR) signed with Shell and Iberdrola during the California energy crisis. Estimated the "down the line" economic burden by comparing the payments under the contracts to prices in comparable contracts and market prices after the end of the dysfunction. Assessed whether the contract prices could be explained by the expected future market fundamentals in the California power markets by using DAYZER market simulation software for the near-term and expected cost of installing and operating a new generation unit for the long-term.
- For estimating breach-of-contract damages, managed a team to support expert testimony in a high-profile international arbitration case. Brattle team built and ran simulation models to forecast power prices and GHG allowance prices in California and the rest of the western states through 2050, accounting for very short-term operational effects as well as long-term capacity expansion needs. The simulation models covered all of the states in the full Western Electricity Coordination Council (WECC) region to capture California's dependency on imports from other areas and changes in price and availability of these imports over time. The modeling team evaluated the impact of GHG policies, RPS policies, changes in load forecasts, changes in hydro conditions, and changes in natural gas prices over time on the power and GHG allowance prices. The simulation models were benchmarked against historical unit dispatch and near term power price forwards to replicate actual market operations and expectations. The Brattle team used the resulting range of power price forecasts under expected range of future market conditions to estimate damages, including an options framework to simulate plant operations and show the threshold conditions for economic shutdown.
- In a New Source Review (NSR) litigation case, analyzed whether the repairs conducted in several coal-fired generation plants should have been expected to result in significant increases in emissions of certain pollutants. The major disagreements were on the choice of baseline emissions and the level of expected impact from the repairs.

- For a group of municipal electric utilities in Massachusetts buying energy from a generating facility under a long-term contract, assisted in evaluating their net benefits from requesting must-run operation of the facility relative to the operations chosen by the seller. The engagement also included a comparison of municipal utilities and investor-owned utilities with respect to their incentives under the Massachusetts Electric Restructuring Act to buy out their power purchase contracts.
- Helped a client in the western United States in a litigation case involving allegations of market power and market dysfunction affecting the prices and other terms of various long-term electricity purchase and sale contracts.
- Managed multiple cases related to estimation of damages resulting from early termination of power contracts.

COAL PLANT ECONOMICS – VIABILITY, RETIREMENTS, AND MARKET IMPACTS

- For the Center for Applied Environmental Law and Policy, co-authored a report to explain the key challenges and opportunities in maintaining a reliable bulk transmission system in the United States electric industry experiencing fundamental change. The report identified: (1) the key trends that have been changing the electricity system and their major drivers; (2) how each trend can support and/or stress various aspects of system reliability; (3) the reforms designed to respond to these reliability effects, and the extent to which the foregoing trends would or would not accelerate the need for such reforms; and (4) in the scenario where reliability reforms are not prioritized to keep pace with industry trends, how compliance flexibilities built into federal environmental regulations (which partly contributes to some industry trends) could help in maintaining reliable system operations nonetheless.
- For environmental and clean energy groups, submitted declarations before the United States Court of Appeals for the District of Columbia Circuit and the Sixth Circuit regarding compliance requirements and flexibility to choose among compliance options under the EPA's Good Neighbor Plan (GNP Rule) for the 2015 Ozone National Ambient Air Quality Standard.
- For the Center for Applied Environmental Law and Policy, co-authored a report on the recent history of changes in the United States coal generation fleet and explained factors contributing to the decrease in coal-fired generation capacity over the past 20 years. The report also summarized the state of market fundamentals and regulations as of 2023 affecting the economics of coal plants in the United States as well as their near- and medium-term outlook. The report explained that provisions in the Inflation Reduction Act

(IRA) that increased the economic attractiveness of clean energy resources prompted some coal plant owners to re-examine the options for their coal fleet.

- For Interstate Power and Light Company (IPL), provided expert testimony before the Iowa Utilities Board regarding the reasonableness of IPL continuing to fully recover the remaining net book value of Lansing Generating Station Unit 4, a coal-fired generating unit, after the unit's retirement at the end of May 2023. Specifically, the testimony reviewed (i) the prudency of IPL's decisions to make major capital investments at Lansing 4 since 2010, based on the then-projected cost-effectiveness of those investments as approved through the Emissions Plan and Budget (EPB) process by the Board; and (ii) the reasonableness of the modeling approach and results in IPL's Clean Energy Blueprint resource plan analysis in 2020 that evaluated the expected cost savings of the retirement of Lansing 4 and the addition of 400 MW of solar generation.
- For Alliant Energy, co-authored a report to describe rail service issues observed in the United States in 2022 and the impacts on coal use in the electric sector. During this period, acute logistical and capacity challenges in rail transportation limited many coal shippers' ability to deliver critical inputs to electric utilities. Rail service delivery issues were widespread throughout the country across many industries with shippers experiencing slower train speed, increased delays, poor on-time performance, and inability to satisfy demand for rail shipments.
- For Wisconsin Power and Light Company (WPL), provided expert testimony before the Public Service Commission of Wisconsin on the appropriateness of WPL continuing to recover as a regulatory asset the undepreciated past investments at the Edgewater 5 coal unit after its proposed retirement in 2022. Reviewed and analyzed the prudency of WPL's past decisions to make those investments and its proposal to retire the unit and replace it with new renewable resources. Explained that longstanding and economically well-justified principles and standards in the utility industry strongly indicated that prudent investments should be fully recoverable from customers, even if they eventually proved less economic than initially projected.
- For an electric utility operating in multiple states, reviewed the utility's draft internal planning studies for evaluating the future cost savings for its customers from early retirements of some coal units. Provided feedback on the reasonableness of the modeling approach and key assumptions of the utility's internal modeling team, suggested potential improvements, and estimated the impacts of the suggested changes on the future cost savings from early retirements of the coal units.

- For the Public Service Company of New Mexico (PNM), managed a team to evaluate the prudency of retiring the San Juan Generation Station (SJGS) and replacing it with renewables and gas peakers, with securitization of remaining undepreciated and adjustment costs. Helped PNM to demonstrate the prudency of its proposed plan based on the findings that i) the expected cost savings and risk reductions of PNM's plan outweighed the option retrofitting the plant with carbon capture, utilization, and storage (CCUS); and ii) securitization was a beneficial approach for providing full cost recovery at low cost to customers, as the state moved to fully clean electricity. The New Mexico Public Regulation Commission ruled in favor of PNM, allowing the utility to abandon SJGS and to securitize up to $360.1 million of unrecovered investments and adjustment costs.
- For Big Rivers Electric Corporation, a municipal electric utility in the Midcontinent Independent System Operator (MISO) market region, provided expert testimony before the Kentucky state regulatory commission to evaluate the economic viability of an existing coal plant against the projected wholesale power prices in MISO. By using an in-house plant dispatch and commitment modeling tool, estimated the future annual capacity factor and variable costs of operating the plant, and compared the plant's avoidable future costs against the projected market prices of energy and capacity for the plant. Developed scenarios for future market prices by considering key uncertainties such as natural gas prices and potential pricing of CO_2 emissions. Estimated the savings from a potential early retirement of the coal plant.
- For an investor-owned electric utility in the MISO market region, provided expert testimony before a United States District Court to assess the potential for economic early retirement of a coal-fired plant under several scenarios including potential future requirements for retrofitting the plant with SO_2 emissions control equipment and future wholesale power market conditions. Estimated the likely impact of retrofits and early retirement on the utility's revenue requirements and retail rates.
- For an electric utility considering an early retirement for one of its coal plants, provided regulatory support to describe the changing economic viability of the existing coal plants in the United States wholesale power markets over the last decade. Conducted research on regulatory decisions in various state jurisdictions on recovery of past investments at retiring generation plants, and explained the perverse incentives on retirement decisions that would be created by disallowing prudently incurred past investments.
- For a merchant generation company in PJM, assessed the potential impacts of coal plant retirements on the future likely range of energy prices under key uncertainties for market fundamentals. The project team evaluated whether the recent price spikes under extreme

weather and system conditions could be repeated in the future with increasing reliance on gas-fired generation plants.

- For an electric utility in Wisconsin, provided expert testimony on the likely changes in energy and capacity prices as a result of projected coal plant retirements and environmental retrofits in the MISO region. The analysis included a transparent model to estimate the impacts of retirements and retrofits on the regional supply curve and the impacts of nationwide coal retirements on natural gas prices. Reviewed the projected reserve margins in the MISO region with and without the coal retirements to evaluate the likely changes in capacity prices in the MISO region after 2016.
- Conducted a screening analysis of coal-fired units in the United States for a producer of biomass fuel that could be an alternative to burning coal in generating units in order to avoid or mitigate future compliance requirements with environmental regulations. The analysis compared the projected costs for each unit under the coal-fired operations (including the retrofit cost of environmental control equipment) against the costs under operations with the alternative fuel and the costs of replacement with a new gas-fired unit.
- For the American Coal Ash Association, conducted annual surveys for the production and use of coal combustion residuals in the United States. The Brattle team designed and implemented the survey circulated to coal generation plant operators and supplemented that information with Brattle's assessment of key market trends in the power industry. The results of the survey were published each year for consumption by energy and environmental agencies and industry analysts.
- For an investor, assessed the economic viability of selected merchant and regulated coal plants in the Midwest. The analysis focused on estimates of projected net revenues for merchant plants and cost of continued operations of the regulated coal plants against replacement power costs. In addition, estimated the projected capacity factor and coal use by each plant under selected future gas and CO_2 price sensitivities.
- Managed a case regarding the estimation of cost and performance benchmarks for two coal-fired generation plants in the eastern United States. Assessed their performance and cost by comparing them with similar coal plants in the country with respect to various performance metrics (heat rate, availability, forced outage rate, etc.) and cost metrics (fuel cost, maintenance costs, capital expenditure). Identified strong and weak points by using various definitions of total costs and key performance metrics and analyzed the tradeoff between good performance and high costs among peer group plants.

RESOURCE PLANNING FOR ELECTRIC UTILITIES

- For an industry association, prepared a report on the potential role of clean hydrogen and other clean dispatchable resources in the future in a decarbonized electric system with a high penetration of variable renewable energy resources. The report summarized the findings and gaps in recent industry studies regarding the key attributes needed from clean dispatchable resources in such a system, including fast and sustained flexibility and ability to store energy across seasons. The report compared the effectiveness, availability and cost of clean hydrogen technologies against other clean dispatchable resources such as gas with carbon capture, small modular reactors, and long-duration storage.
- For the Clean Power Suppliers Association, performed a detailed review of the Carbon Plan, which is Duke Energy's recent integrated resource plan study on alternative resource portfolios to achieve 70% reduction in Duke Energy's North Carolina CO_2 emissions by 2030 relative to its 2005 emissions. Identified a number of modeling assumptions that made the comparison of costs across the portfolios flawed. Replicated the Carbon Plan modeling results through its GridSIM capacity expansion and production cost modeling software and simulated additional alternative portfolios that would result in lower future costs for Duke's customers.
- For Cypress Creek Renewables, prepared an economic study to analyze the generation costs and emissions impacts of a future resource mix for Duke Energy that achieved the requirements outlined in North Carolina's House Bill 951 (H951) and minimized the additional development of natural gas capacity. The study concluded that by shifting its resource mix from coal and gas resources to renewable energy and battery storage, Duke Energy could achieve over 70% GHG emissions reductions by 2030 (relative to 2005 emissions) while lowering generation costs. The study also found that use of securitization to finance the recovery of undepreciated past investment costs at some of the retiring coal plants was a major driver of the customer cost savings in addition to the avoided fixed operating and ongoing capital expenditures from early retirements.
- For a large Midwest utility serving electric and gas, assessed current and likely future industry developments with potential to create opportunities and risks for the regulated and nonregulated operations of the company. The key developments included emerging EPA air quality, water and ash regulations for power plants, potential climate policies, macroeconomic recovery, and smart grid technologies. In addition, conducted a comparison of the risks and cost of capital associated with regulated and unregulated businesses, including behind-the-meter renewable generation. Presented the findings of these assessments to the board of directors.

- Assisted a municipal electric utility in developing a least-cost strategy to comply with environmental regulations. Developed a screening tool to compare the economics of environmental retrofits against alternatives such as replacement with a new gas-fired combined cycle or relying on market purchases of energy and capacity to meet the retail load obligations. Presented the results of the economic analysis and potential hedging strategies to the executive management.
- Co-authored a chapter of an EPRI report on decision-making complexities and factors in utility resource planning and environmental compliance investment decisions. The chapter described how various metrics of cost and performance could be used by power industry planners and executive decision makers, the limitations of those metrics and modeling techniques, and how this problem and modeling complexity may alter the type and timing of technology preferences. Some of the complexities were illustrated with examples on retire/retrofit choices for coal plants to comply with the environmental regulations and on decision-making for Carbon Capture and Sequestration (CCS) investment under CO_2 price volatility.
- Assisted an electric utility in the Midwest in their resource planning. Developed environmental regulation scenarios with the executives and experts at the utility, and assisted in modeling and reviewing the implications of regulatory and market scenarios on the least-cost strategy subject to meeting load, renewable energy standards, and capital constraints. The strategy options included retrofitting the coal-fired generation plants with necessary control equipment, retirement of coal-fired units and replacement with gas-fired units. Presented results to the utility executives.
- Assisted an electric utility in developing an Integrated Resource Plan under potential climate policy scenarios. The plan was developed by reviewing and choosing the best mix of supply side alternatives and demand side programs that would achieve the joint objectives of minimizing cost and mitigating CO_2 footprint subject to meeting the utility's obligation to serve its customers. The supply side options included combinations of conventional generation technologies, renewables and low CO_2 fossil fired generation, and new transmission investment.
- For a large independent generation company, led a team to assess the reasonableness of the evaluation procedures and criteria used by an electric utility in the southern United States in its RFP to acquire new generation assets and power purchase agreements. Reviewed the RFP requirements and the papers supporting the RFP results in a brief period of time to identify the questionable assumptions and criteria used by the electric utility, and quantified the impacts of these on the relative costs of bids.

- For EPRI, analyzed and reviewed the major drivers of generation technology choice in various countries and regions around the world. Although the availability and degree of access to fuels was a common driver, other factors such as capital cost, attitude towards nuclear technology and renewables, constraints on carbon-intensive technologies, and degree of economic development played a varying degrees of roles in the choice of generation fuels and technologies in each country.

ENVIRONMENTAL AND CLIMATE POLICIES – DESIGN AND IMPLICATIONS

- For a merchant generation owner in New England, managed a team to conduct an economic study on the potential cost and emission impacts of making the existing clean energy generators eligible under an expanded Clean Energy Standard (CES) program in Massachusetts. Under the existing CES program, commercial operating date requirements limited eligibility to clean energy generators commencing operation after 2010. The study concluded that retaining existing clean generation that came online prior to 2010 under the CES program would reduce GHG emissions in Massachusetts and New England, and would reduce system production and customer costs.
- For a power industry association, co-authored a study to assess the carbon emission impacts of premature nuclear retirements. The study concluded that the vulnerability of some nuclear power plants to premature retirement could create a major threat to the attainment of desired CO_2 reduction. The analysis found that the retirement of a 1,000 megawatt nuclear plant could increase CO_2 emissions in the range of 4.1 to 6.7 million tons per year, or 0.52-0.84 tons per MWh of nuclear generation lost, depending on the region in which the nuclear retirement occurs. In addition, the increased level of CO_2 emissions arising from a premature nuclear retirement would not be confined to the state in which the unit resides. In fact, in most cases the majority of this increase would occur outside the state, and a significant amount of the emissions increase would occur in states beyond those adjacent to the state experiencing the retirement.
- For an industry association, co-authored a study to analyze the potential implications for competitive wholesale electricity markets if new gas-fired combined cycle (CC) plants were not covered under the Clean Power Plan's (CPP) mass-based state implementation plans (SIPs). The authors found that if state implementation plans excluded new gas CC plants, the electric sector could fall short of the carbon dioxide (CO_2) reduction goals set by the CPP, while incurring higher system costs per ton of CO_2 avoided. In addition, Brattle simulations illustrated that excluding new gas CCs from the emissions cap would introduce a discrepancy in the economics facing new and existing gas CCs that were identical in all

respects other than their in-service dates. New CCs would earn greater profits in the energy market because they would be compensated as if they were entirely non-emitting plants.

- For a power industry association, conducted analysis of the EPA's proposed rule for regulating CO_2 from existing sources under Section 111(d) of the Clean Air Act, focusing on potential economic impact to hydropower. Summarized key aspects of the rule, and assessed how the compliance options for states could differ from the BSER options in setting target rates and how states could utilize hydropower (existing or new) as a compliance option under the rule.
- For a western electric utility, evaluated the EPA's development of CO_2 rate targets in Arizona and assessed the reasonableness of projected pace and level of emission reductions. Conducted a detailed assessment of the assumptions and modeling approach in EPA's IPM simulations and identified areas of improvements. Prepared a whitepaper to summarize the findings to be filed as part of the utility's comments to the EPA.
- For an electric utility in the western US, conducted a study to assess reliability and supply-chain implications of compliance with the EPA's Regional Haze Rule. The Regional Haze Rule aimed to reduce haze-forming pollution (primarily due to emissions of particulate matter and its precursors SO_2 and NOx) that reduced visibility in parks and wilderness areas, especially in the western United States. Assessed the impact of outages at coal units to tie-in the environmental retrofit equipment on available resources to meet the utility's load obligations in the future. In addition, compared the historical retrofits on coal units in the region against projected retrofits to comply with Regional Haze Rule.
- Co-authored a study commissioned by the MISO to evaluate the feasibility of the large number of simultaneous environmental retrofits and new generation that might be needed for coal plants to comply with the Environmental Protection Agency's Mercury and Air Toxics Standards (MATS) rule. The study found that compliance with the MATS rule posed significant challenges. The study took into account the historical level of actual retrofits and new generation construction, typical timelines to complete various types of projects, potential bottlenecks in specialized types of labor, and the required planned outages in coal plants to install and test the environment control equipment.
- Co-authored studies that analyzed the economics of retirement decisions for each coal plant operating in the United States under proposed and emerging EPA air quality and water regulations, taking into account the predicted profitability and cost of replacement power for both regulated and unregulated plants. The regulations were expected to force coal plants to decide between retiring versus installing expensive control equipment to

reduce emissions of SO_2, NOx, particulates, and hazardous air pollutants such as mercury, as well as cooling towers to reduce the use of cooling water.

- For a natural gas producer, analyzed the potential for change in natural gas demand as a result of the Waxman-Markey climate policy proposal. Using scenarios for new renewable capacity and price of natural gas relative to coal, analyzed effects of CO_2 prices on dispatch switching from coal-fired to gas-fired generation plants in various ISO regions, as well as on demand for gas in non-electric sectors.
- Assisted an electric utility in understanding the implications of the Waxman-Markey climate policy proposal on its renewable generation portfolio and its electricity sales to other regions. Identified opportunities and risks for specific renewable technologies due to provisions in the bill imposing renewable portfolio standards for electric utilities.
- For electric utility companies in the eastern United States, analyzed the potential effects of existing and developing environmental legislation and regulation on the existing generation fleet. The assignment included reviewing and summarizing the regulations by pollutant, identifying the specific generation plants that these regulations could affect, and estimating economics of retirement for each plant under a regulatory scenario.
- Conducted screening analyses for electric utilities to assess their exposure to allowance costs in the near- and long-term due to recent cap and trade climate policy proposals. Under alternative assumptions to comply with the regulations (from complete reliance on allowance purchases to reducing emissions to meet the economy-wide targets), estimated the potential cost of the policy net of free allowances under the proposal using various CO_2 price scenarios.
- For an electric utility, assisted in evaluating expected natural gas prices under potential CO_2 prices due to proposed federal climate policies in the United States. The analysis included modeling of changes in demand for natural gas in electric and non-electric sectors as a result of potential CO_2 prices, as well as feedback effects due to dispatch switching from coal-fired generation plants to gas-fired generation plants in electric sector.
- Helped a large energy company evaluate the implications of several climate policy options on United States CO_2 emissions from electric and transportation sectors, and consumption and prices of electricity, natural gas, and coal. The analysis focused primarily on long-term implications for future generation capacity mix and provided insights about the feedback effects between fuel prices, electricity prices, and electricity consumption.

WHOLESALE MARKET ANALYSIS AND ASSET VALUATION

- For MISO, evaluated design options for the resource adequacy market to provide efficient signals to resource owners for making their resources available during hours when the system was at or near scarcity conditions. As a result of the increasing penetration of renewables in the MISO region, as well as the increasing prevalence of common mode failures at fossil-fuel generation plants, MISO evaluated design options with the understanding that critical resource adequacy periods would increasingly include periods outside the summer peak load hours. Evaluated alternative mechanisms for accreditation of resources under a sub-annual resource adequacy construct and for MISO's modeling of planned and forced outages in determining planning reserve requirements, and compared these mechanisms against practices of other system operators.
- For an asset management firm considering investing in a virtual trading company with operations in Regional Transmission Organizations (RTOs), performed due diligence analysis on the trading algorithm, profitability, achievable market size, and compliance with market monitoring rules.
- For a large electric utility in Canada, researched industry practices on the wind integration service rates charged by balancing authorities in the United States outside the organized wholesale power markets.
- For a group of market participants in Texas, managed a team to estimate the impacts of implementing marginal losses in the ERCOT market on system production costs, transmission losses, LMPs, load payments, and generator revenues. Simulated the ERCOT power system using PSO software, and calibrated the model to recent generation and load patterns. The study results were made public in a proceeding before the Texas Public Utility Commission.
- For a large group of generation owners and trade groups, conducted a study to estimate the above-market payments to certain merchant generation plants with 90-day fuel supply under the United States Department of Energy's (DOE) proposed payments. While the DOE's rationale for the proposed payments was to improve the resilient operations of the power system, the study concluded that 1) there was no evidence supporting the premise that 90 days of on-site fuel at individual power generating plants would improve the resilience of the grid in the regions where the rule would apply, and that 2) implementing the proposed rule would undermine core market principles and diminish some of the most important advantages of competitive wholesale power markets.

- For a developer of a biogas power plant, submitted expert testimony on the outlook of projected long-term wholesale power prices in Arizona. Reviewed forward market prices for near term deliveries as of the execution date of a contract with the supplier of waste feedstock, and summarized the industry expectations for the timing of the need and cost to build new generation in the region.
- For a developer of solar PV generation plants, conducted research and analyses to identify potential opportunities for renewables to be offered to electric utilities as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA). Summarized the states with the largest penetration of renewable QFs and most favorable contract/pricing terms, and presented the likely outlook on avoided cost rates by region.
- For an investment firm, evaluated the projected net margins from energy and capacity markets in the Northeast for a new gas-fired generation plant. Assessed the key market drivers and risk factors associated with the plant's future performance and conducted analyses to assess the implications for the asset's market value.
- For an independent power producer, analyzed the market trends in California power markets and explored potential value drivers of the client's existing gas-fired combined-cycle plant in California. Simulated the long-term wholesale energy prices in the Southern California region and developed a modeling tool to analyze the projected capacity payments for existing resources under the California's local resource adequacy construct.
- Assisted an electric utility in performing a valuation of a coal-fired unit. Managed the analysis to model the projected revenues from energy and capacity markets, as well as to project variable and fixed operating costs and environmental compliance costs in the future. Various market and regulatory scenarios were considered and presented to the client.
- For an investor, performed a valuation analysis of a potential new gas combustion turbine (CT) in Texas. Developed scenarios for future energy-only and capacity markets, estimated regional reserve margins under a few load-growth scenarios. In addition to estimating annual energy margins using a virtual commitment and dispatch model, estimated the projected run-hours for the new CT.
- For an investor, co-authored a valuation analysis of a large gas-fired cogeneration facility in the Midwest. In addition to projecting energy and capacity prices in the region under the key uncertainties on gas prices, coal plant retirements, and renewable generation additions, the study analyzed the projected revenues under the existing long-term sale contracts to provide energy and steam.

- Co-lead team to assist a municipal electric utility in the Midwest United States to sell a portion of its share of energy and capacity from a new coal plant. Acted as sale advisor to design the sale process, solicit bids, prepare informational documents, and evaluate the bids.
- For an RTO in the Midwest United States, estimated the future costs and benefits from an electric utility joining that RTO as a member, compared to stand-alone and an alternative RTO membership. The analysis included impact on production cost savings, existing transmission constraints and interconnection capacities, wholesale trading activity, load diversity benefits, generation investment savings, and allocation of transmission costs and revenues.
- For a power plant developer, estimated the market potential for new wind, solar and gas peaking plants in the Eastern Interconnection. Developed and refined assumptions and scenarios on future fuel prices, capital costs of new plants, federal tax credits as well as federal climate policy. Economic potential for new generation alternatives were estimated by using Brattle's in-house simulation model Xpand, which optimized plant dispatch as well as generation entry and retirements in order to meet future electric demand and reserve margin requirements.
- For an electric cooperative in the Midwest, conducted studies to evaluate the impact of planned new wind and gas combined-cycle units at alternative locations on nodal energy prices and net revenues for generation fleet owned by the cooperative. Provided analytical support to assess likely allocations of auction revenue rights for hedging congestion.
- For a large merchant generation company in PJM, assessed the likely causes of high energy prices during polar vortex events. Analyzed the impact of each driver on market prices, and conducted simulations to evaluate the likely market prices in the future under similar weather conditions and sensitivities for coal plant retirements, increased penetration of demand-resources, and expected gas prices.
- For a large coal company, assisted in designing and evaluating innovative coal supply contracts with power plants. Developed a customized tool to simulate the regional energy and capacity prices in the eastern power markets and evaluated the profitability of various types of supply contracts from the perspective of the coal company and the power plant. In addition, identified coal-fired power plants that could be potential candidates to benefit from signing innovative coal supply contracts.
- For a group of electric utilities in the Midwest, led a team to assess the energy-related costs and benefits of joining an RTO. Using a nodal pricing simulation software, estimated the net

costs to customers of the utilities with respect to energy, congestion, marginal losses, and allocation of financial transmission rights and loss refunds under each configuration (stand-alone and RTO membership).

- For clients in PJM, examined the variability of historical congestion patterns to help assess the reasonableness of the utilities' strategies to acquire financial transmission rights (FTRs) and Auction Revenue Rights (ARRs).
- Provided consulting services on the impact of moving into a locational marginal price (LMP) market design for a client in the Western Electricity Coordinating Council. In addition to quantifying the expected congestion cost exposure under LMP market design, examined the impacts of potential mitigating solutions on the cost exposure and on the client's ability to hedge these costs through acquisition of financial instruments.
- Estimated the economic benefits of a proposed power plant in California. The project included an analysis of benefits from reduced market-clearing prices, avoided/deferred transmission upgrades, and reliability improvements.
- For an independent power producer, assessed the competitive offer price for its planned gas-fired generation unit in the PJM capacity market. Under key scenarios reflecting uncertainty in market fundamentals and in reasonable modeling assumptions, estimated the net cost of new entry (Net CONE) for the generation plant using plant-specific cost and performance information supplemented by publicly available estimates for generic plants. The key modeling assumptions driving the range of results were the appropriate methodology to levelize overnight capital costs and the appropriate time period over which the costs of the generation plant would be recovered in the PJM markets.
- Assisted an energy company to understand the fundamentals of the PJM capacity markets to inform the company's bidding strategy in the capacity auctions. Conducted a training session to review the auction clearing mechanism, simulation of the market-clearing prices and quantities and alternative methodologies to project future market supply curves.
- For an energy trading company in the western United States, assessed the California Independent System Operator's (CAISO's) historical calculations of nodal energy prices at specific locations. The focus of the assessment was to understand the impact of modeling differences between day-ahead energy markets and annual Congestion Revenue Rights (CRRs) auctions on the nodal energy prices at those locations. The findings of this assessment were used to support a complaint at the FERC.
- For a transmission owner in Canada, assessed whether the proposed procedures to coordinate the Available Transmission Capacity (ATC) on its interfaces with neighboring

systems were consistent with the FERC requirements and the practices of various United States counterparts. ATC coordination was required under FERC Order 890 in order to ensure that ATCs were calculated in a consistent manner by transmission providers and that transmission service was provided in a non-discriminatory manner.

- For an RTO in the eastern United States, assisted in the preparation two expert reports regarding an alleged manipulation of market credit rules through its trading activity in the FTR markets. The analysis involved a review of trading activity and an assessment of risks assumed by the trader through a review of historical congestion prices.
- Submitted rebuttal and surrebuttal testimony jointly before the Pennsylvania Public Utilities Commission on the causes of an episode of high locational marginal prices (LMPs) experienced by a small electric utility in PJM wholesale energy markets. Using data on potential causes of high congestion and detailed market simulation modeling, identified several causes including increased virtual bidding activity, reduced transmission capability, and changes to physical characteristics of certain transmission assets.
- For an electric utility considering joining an RTO, managed transmission flow analyses of generation and load deliverability, as well as LMP market simulations to assess the effects of the company's move on prices in its service territory.
- Co-authored a report reviewing the results and the performance of the ISO-NE Forward Capacity Market (FCM) auctions conducted for the 2010/2011 and 2011/2012 commitment periods.
- Submitted an affidavit at the Public Utilities Commission of Texas (PUCT) regarding a proposed rule to allocate costs of procuring replacement reserves to market participants in ERCOT.
- Analyzed the economic and network impacts of a utility signing renewable energy contracts with several potential renewable generation projects. Using market simulation tools such as MarketSymTM and PowerworldTM, simulated an entire reliability council to assess whether each of the potential renewable generation projects would cause additional transmission constraints, and estimated the impacts of these projects on LMPs across the region.
- Assisted an electric utility before the energy regulator in Quebec, Regie De l'Energie, involving third-party access to an electric transmission system owned and operated by another company.
- Assisted numerous clients in examining the potential for the exercise of horizontal and vertical market power under the FERC's market power tests as a result of asset acquisitions, mergers, and as part of periodical market-based rate (MBR) filings.

- Helped a client assess the potential liability and market impacts associated with offering the output of an out-of-service generation unit to the ISO-NE markets.
- Led efforts to prepare a report assessing the implications of the Open Access Transmission Tariff (OATT) filed by MISO on market efficiency and gaming opportunities.
- Contributed to Brattle's investigation of the California power crisis on issues involving physical or economic withholding and manipulative gaming strategies such as double-selling, circular scheduling, wheel-out, simulation of real-time energy, and ancillary services markets.
- Estimated the potential for the exercise of market power in a load pocket in the Northeast United States power markets. The study simulated strategic behavior in order to assess the price risk for a distribution company due to congested transmission facilities.

RETAIL ELECTRIC RATES – COST ESTIMATION AND RECOVERY

- For an electric utility in the western United States, managed a team to support expert testimony before Oregon and Wyoming regulators with respect to the appropriate recovery mechanisms for fuel and purchased power costs. Demonstrated the historical persistency of under-recovery of such costs due to the inherent asymmetric nature of the difference between actual net purchased power costs and year-ahead deterministic forecasts. Compared the existing true-up methodology for that utility against common industry practices across the United States with respect to the use of variance deadbands, earnings tests and sharing arrangements between ratepayers and shareholders.
- For multiple clients including a university, several hospitals and a hotel and shopping complex in Pennsylvania, conducted economic due diligence studies on the potential cost savings from installing an on-site combined heat and power (CHP) facility that would offset power and heating needs. Reviewed key drivers of potential cost savings, including net metering revenues from excess generation output from the CHP plant, reduction in cost of purchasing grid power, and future market prices for power and fuels. Presented findings to the executive teams and provided analytical support in contract negotiations.
- For an investor in distributed gas-fired generation assets in Texas, conducted a study on future savings in transmission and distribution service costs and potential market penetration of distributed energy resources. Reviewed key aspects of the wholesale market structure that directly impact the long-term stability of the transmission tariff rate, and identified potential risks and mitigating factors associated with possible changes to the design of the market.

- In a merger involving two electric companies in the eastern United States, analyzed the impacts of the merger on competition in retail electricity markets. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in several states. The analysis involved assessment of whether the increased market share in wholesale energy markets would affect retail competition, number of suppliers in retail electricity markets, ease of entry and exit to provide electricity to retail customers directly or through Default Service (DS) procurements, and potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.
- For an association of suite meter providers in Canada, analyzed whether the incumbent electric utility had been cross-subsidizing the provision of suite meters to its residential customers at the expense of its other customers. The analysis involved a comparison of the estimated fully-allocated costs of providing suite meters to the net revenues from these customers under the regulated retail rates under alternative assumptions on the costs of meters and types of suite meter installations.
- Prepared a marginal cost study for an integrated electric utility in the PJM region. The study estimated the incremental costs to the utility of serving additional demand and customers by time period, sub-region, and customer class.
- For a large electric customer of a utility in the western United States, assisted in evaluating the utility's proposed rate design. Specifically, provided an assessment of alternative methods to classify generation costs (as demand, energy, or customer related) and to allocate the fixed costs among customer classes. The analysis included an assessment of the treatment of the costs and revenues associated with off system sales in determining the revenues to be recovered from various customer classes.
- For an electric customer in United States, analyzed whether a proposed change in rates by the electric utility would result in just and reasonable rates for transmission level and station service customers. The resulting testimony assessed whether the proposed rates were consistent with fundamental principles of ratemaking such as cost causation and rate stability, and compared the proposed rate design to the rate options provided by utilities in other jurisdictions for transmission level and station service customers. The parties settled the case with reduced rates for the client based on the lower cost of serving transmission level customers relative to distribution level customers.
- For an electric utility planning to install smart meters and in-home displays in the eastern United States, assisted in estimating the likely benefits to retail customers and to the utility. The quantified benefits to the utility company mostly came from reduced costs of meter

reading and outage managements, whereas the customer benefits came from reduced costs of energy, capacity, and carbon emissions as a result of reduced peak load and annual energy consumption.

- Co-managed a case regarding a Texas electric utility company auctioning off its generation assets in order to determine its stranded costs. Assessed whether the market value of the utility's jointly-owned generation assets was depressed due to the rights of first refusal (ROFR) provisions attached to these assets, and whether the utility company failed to take commercially reasonable steps to mitigate its stranded costs.
- Helped a client analyze the cost of providing ancillary services (reserves, regulation, voltage support, etc.) from its hydroelectric generation facilities. The analysis dealt with the implications of separating cost of energy and ancillary services on the electricity rates of different customer types.

ARTICLES & PUBLICATIONS

- "Bulk System Reliability for Tomorrow's Grid," with Andrew Levitt, Andrew Thompson, Ragini Sreenath, Xander Bartone, Sam Willett, and Hazel Ethier, prepared for the Center for Applied Environmental Law and Policy, December 20, 2023.
- "Role of Hydrogen in a Decarbonized Future," with Josh Figueroa and Andrew Thompson, presented at the Bank of America 2023 Hydrogen Conference, December 19, 2023.
- "A Review of Coal-Fired Electricity Generation in the US," with Long Lam, Jadon Grove and Natalie Northrup, prepared for The Center for Applied Environmental Law and Policy, April 27, 2023.
- "Rail Delivery Disruptions in the US in 2022: An Overview of Scale and Extent," with Nicholas Powers, prepared for Alliant Energy, March 30, 2023.
- "A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation," with Michael Hagerty, Matt Witkin, Julia Olszewski, and Frederick Corpuz, prepared for Cypress Creek Renewables, August 31, 2021.
- "Western Energy Imbalance Service and SPP Western RTO Participation Benefits," with John Tsoukalis, Johannes P. Pfeifenberger, Sophie Leamon, Carson Peacock, and Sharan Ganjam, prepared for Southwest Power Pool, December 2, 2020.

- "The Role of Economics in Evaluating Contractual Performance Defenses: Emerging Disputes on COVID-Related Force Majeure Claims," with Shaun D. Ledgerwood, Peter S. Fox-Penner, and Jake Zahniser-Word, September 2020.
- "The Brattle Group's Notes on the Affordable Clean Energy Rule," with David Luke Oates, Michael Hagerty, Yingxia Yang, and Marc Chupka, August 23, 2018.
- "The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum," with Richard Sweet, Kelly Oh, and Marc Chupka, prepared for the Advanced Energy Economy (AEE), American Petroleum Institute (API), American Wind Energy Association (AWEA), Electricity Consumers Resource Council (ELCON), Electric Power Supply Association (EPSA), and Natural Gas Supply Association (NGSA), July 19, 2018.
- "New Technologies and Old Issues under PURPA," with Robert S. Mudge, Marc Chupka, and Peter Cahill, Norton Rose Fulbright's *Project Finance NewsWire*, February 26, 2018.
- "The Future of Cap-and-Trade Program in California: Will Low GHG Prices Last Forever?" with Yingxia Yang, Michael Hagerty, Ashley Palmarozzo, Hannah Sheffield, Marc Chupka, and Frank C. Graves, December 5, 2017.
- "Comments on Expanding CES Eligibility to Existing Nuclear Units," with Onur Aydin, David Luke Oates, Tony Lee, and Kelly Oh, prepared for NextEra Energy Resources and presented to the Massachusetts Department of Environmental Protection in response to the proposed Clean Energy Standard-Existing (CES-E), November 30, 2017.
- "The Future of the U.S. Coal Generation Fleet," with Marc Chupka, Dean M. Murphy, Samuel A. Newell, and Ira H. Shavel, ABA Antitrust Section Transportation and Energy Industries Committee Fall 2017 newsletter, November 30, 2017.
- "Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule," with Judy Chang, Marc Chupka, Samuel A. Newell, and Ira H. Shavel, prepared for NextEra Energy, Inc., October 26, 2017.
- "Impacts of Marginal Loss Implementation in ERCOT," with Toshiki Bruce Tsuchida, Rebecca Carroll, Colin McIntyre, and Ariel Kaluzhny, prepared for Ad Hoc Group, including Vistra Energy, The Wind Coalition, and First Solar, October 11, 2017.
- "Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource," with Marc Chupka, Frank C. Graves, Dean Murphy, and Ioanna Karkatsouli, December 2016.
- "Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan: Implications for Economic Efficiency and Wholesale Electricity Markets," with Judy Chang, Kathleen Spees, and Tony Lee, November 2016.

- "The Clean Power Plan: Focus on Implementation and Compliance," with Marc Chupka, Judy Chang, Ira H. Shavel, Kathleen Spees, Jürgen Weiss, Pearl Donohoo-Vallett, Michael Hagerty, Michael A. Kline, prepared as a Brattle Policy Brief, January 2016.
- "EPA's Proposed Clean Power Plan: Implications for States and the Electricity Industry," with Kathleen Spees, Michael Hagerty, Samuel A. Newell, Dean Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira Shavel, prepared as a Brattle Policy Brief, June 2014.
- "Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices," with Onur Aydin and Frank C. Graves, November 2013.
- "Potential Coal Plant Retirements: 2012 Update," with Frank C. Graves and Charles Russell, published by The Brattle Group, Inc., October 2012.
- "Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS," with Kathleen Spees, Quincy Liao, and Steve Eisenhart, May 2012.
- "State Regulatory Hurdles to Utility Environmental Compliance," with Philip Q. Hanser and Bin Zhou, *Electricity Journal*, April 2012.
- "Decision Complexities in Utility Resource Planning and Environmental Compliance Investment," with Frank C. Graves, chapter in EPRI report "The Market Backdrop to US Power Generation Coal Technology Goal-Setting and Learning, September 2011.
- "Marginal Cost Analysis in Evolving Power Markets: The Foundation of Innovative Pricing, Energy Efficiency Programs, and Net Metering Rates," with Philip Q. Hanser, The Brattle Group Energy Newsletter Issue 2, 2010.
- "Virtual Bidding: The Good, the Bad, and the Ugly – Experience of RTOs with Virtual Bidding and Implications for Market Participants' Hedging Congestion Costs," with Attila Hajos and Philip Q. Hanser, *Electricity Journal*, June 2010.
- "Can the US Congressional Ethanol Mandate be Met?" with Evan Cohen, Michael I. Cragg, David Hutchings, and Minal Shankar, The Brattle Group Discussion Paper, May 2010.
- "Prospects for Natural Gas Under Climate Policy Legislation: Will There be a Boom in Gas Demand?" with Steven H. Levine and Frank C. Graves, The Brattle Group Discussion Paper, March 2010.
- "Internal Market Monitoring Unit Review of the Forward capacity Market Auction Results and Design Elements," with Dave Laplante, Hung-po Chao, Samuel A. Newell, and Attila Hajos, filed at FERC by ISO-NE, June 5, 2009.

- "CO_2 Price Volatility: Consequences and Cures," with Frank C. Graves, The Brattle Group Discussion Paper, January 2009.
- A Lexicon Entry for "A Theory of Incentives in Procurement and Regulation – Laffont&Tirole," with Richard Arnott, Lexikon der Okonomischen Werke, 2006.
- Contributing author for the Energy Bar Association Antitrust Committee's report on 2005 Antitrust Development.
- "The CAISO's Physical Validation Settlement Service: A Useful Tool for All LMP Based Markets," with Philip Q. Hanser, Jared S. des Rosiers, and Joseph B. Wharton, *Electricity Journal*, October 2005.
- "The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings," with James Bohn and Philip Q. Hanser, *Electricity Journal*, May 2002.
- "Financial Transmission Rights: Implementation Issues," with Philip Q. Hanser, Working Paper, February 2002.
- "An Analysis of Incentives and Regulation in Providing Capacity and Reliability in Power Transmission Networks," unpublished PhD thesis for Boston College, September 2000.

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Cashing In On CHP: Increasing Energy Reliability and Savings with Combined Heat and Power (CHP)," with Frank C. Graves, Alan Seltzer, and John Povilaitis, June 3, 2021.
- "FERC's Recent Ruling on PURPA: Variable Energy Rate Option," EUCI Online Conference, December 15, 2020.
- "PURPA Notice of Proposed Rulemaking 2019," NRRI PURPA Perspectives Webinar, January 29, 2020.
- "PURPA Resurgence and Avoided Costs," EUCI Symposium, September 9, 2019.
- "Future of Coal: Clean Power Plan, Market Drivers, and Other Regulations," American Coal Ash Association's (ACAA) 2017 Winter Membership Meeting, January 25, 2017.
- "CO_2 Regulations and Coal," Energy Bar Association's (EBA) Energizer: Ongoing Climate Imperative, November 10, 2016.
- "Update on Clean Imperative and Sectoral Responses in the US Power Industry," with Robert S. Mudge, Susan Nickey, Allyson Umberger Browne, and Elias B. Hinckley, American Bar Association (ABA) Business Law Section's Annual Meeting, September 8, 2016.

- "The Clean Power Plan: Retirements and Reliability," Wisconsin Energy Institute 2015 Energy Summit, October 2015.
- "The Clean Power Plan: Retirements and Reliability," with Michael Hagerty, Yingxia Yang, and Nicole Irwin, EUCI Conference, April 1, 2015.
- "Hydropower and the EPA Section 111(d) Proposal," with Marc Chupka and Kathleen Spees, National Hydropower Association, August 12, 2014.
- "Coal Plant Retirements and Market Impacts," Wärtsilä Flexible Power Symposium, February 5, 2014.
- "U.S. Coal Plant Retirements: Outlook and Implications," Coaltrans West Coast Conference, June 14, 2013.
- "U.S. Coal Plant Retirements: Outlook and Implications," West LegalEd Center CLE Webcast, January 24, 2013.
- "Environmental Retrofits: Costs and Supply Chain Constraints," MISO Annual Stakeholders' Meeting, June 2012.
- "Potential Coal Plant Retirements in U.S. and Impact on Gas Demand," CERI Conference, February 27, 2012.
- "Potential Coal Plant Retirements and Retrofits Under Emerging Environmental Regulations," Minnesota Rural Electric Association (MREA) Annual Meeting, August 10, 2011.
- "Potential Coal Plant Retirements in ERCOT Under Emerging Environmental Regulations," with Frank C. Graves, Public Utility Commission of Texas workshop on Potential Environmental Regulations and Resource Adequacy, June 22, 2011.
- "The Regulatory Landscape for Coal-Fired Power: EPA Rules and Implications," with Frank C. Graves and Marc Chupka, EUCI Conference, January 24, 2011.
- "Potential Coal Plant Retirements under Emerging Environmental Regulations," with Frank C. Graves, Gunjan Bathla, and Lucas Bressan, EUCI Webinar, December 8, 2010.
- "Financial Instruments in Power Markets: Virtual Bids and FTRs," with Attila Hajos and Philip Q. Hanser, EUCI Conference, July 19, 2010.
- "Marginal Cost Studies in Ratemaking and Implications of Federal Climate Policy," Southeastern Electric Exchange Rates and Regulation Section Meeting, October 28, 2009.

- "CO_2 Price Volatility Delays Clean Generation Investment," Law Seminars International's Renewable Energy in New England Conference, June 25, 2009.
- "What to Expect from Electric Power and Transport Sectors in Response to U.S. Climate Policy," Rutgers University Center for Research in Regulated Industries, January 18, 2008.
- "Financial Transmission Rights: Necessary or Burdensome?" with Philip Q. Hanser, IAEE Conference, June 7, 2006.
- "Regulation of Transmission Investment and Reliability in Power Networks," METU International Conference in Economics V, September 2001.

SELECTED HONORS & AWARDS

1999	Summer Dissertation Award, Boston College Graduate School of Arts and Sciences
1998	Summer Dissertation Award, Boston College H. Michael Mann Fund
1991–1993	Scholarship, Yasar Holding Company
1988–1993	Tuition Scholarship and Stipend towards the completion of BSc in Industrial Engineering, Turkish Ministry of Education

PROFESSIONAL ASSOCIATIONS & MEMBERSHIPS

2021–Present	**American Bar Association (ABA)** *Sections: Litigation; Environment, Energy, and Resources; Infrastructure and Related Industries*
2022–Present	**Energy Bar Association (EBA)**

LANGUAGES

- Turkish (native)

DECLARATION OF BEN GROVE IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

I, Benjamin Grove, declare as follows:

Background and Expertise

1. I have a B.S. in Petroleum Geology & Geophysics (2015) and an M.S. in Geology (2018) from The Ohio State University.

2. From 2013 to 2015, I worked at Battelle Memorial Institute, primarily on U.S. Department of Energy (DOE) sponsored carbon storage research projects, where I worked on the technical and regulatory aspects of CCS projects.

3. From 2018 to 2021, I continued working at Battelle, assisting in and leading geotechnical and economic assessments of commercial CCS projects across the United States. During this time, I helped develop Battelle's commercial CCS business, which pivoted from DOE-funded research to commercial projects following the amendment of the 45Q tax credit in 2018. I was in regular communication with and presented to a wide variety of commercial clients, including energy and fuel producers. I also led the development of a CCS cost model for feasibility studies, which included pipeline cost estimations.

4. At Battelle, I routinely worked on feasibility studies for commercial CCS projects which included the full value chain of CCS, from capture to transportation and storage.

5. Throughout my career, I have worked on numerous CCS-related DOE projects, such as CarbonSAFE, Midwest Regional Carbon Sequestration Partnership, Midwest Regional Carbon Initiative, and others. These projects have provided me with extensive experience in the planning, design, and implementation of CCS projects, including the associated pipeline infrastructure.

6. In addition to my work in the United States, I led the development of the project management and assurance plan for the Asian Development Bank-funded Gundih CCS pilot project in Central Java province of Indonesia. This work included planning for pipelines and project development scheduling, as well as logistics for a pilot CCS project in the natural gas processing sector.

7. Since 2013, I have been working on geologic storage, techno-economics of carbon capture and storage, and associated business models.

8. In 2023, I was the first author on the LLNL/CATF report "Sharing the Benefits: How the Economics of Carbon Capture and Storage Projects in California Can Serve Communities, the Economy and the Climate." This report examined CCS costs for a range of project types in California. I co-wrote the report, provided capture cost data, and performed the cost modeling for pipeline transport and geologic storage.

9. I am currently employed at Clean Air Task Force, an environmental non-profit organization, where I designed and oversaw our work on national power plant CCS and offshore mid-Atlantic infrastructure buildout studies, which

involved extensive analysis of pipeline infrastructure requirements for large-scale CCS deployment.

10. I continue to contribute to numerous reports on CCS as both an author and reviewer.

11. This declaration is submitted in support of Environmental and Public Health Respondent-Intervenors in their opposition to Petitioners' stay motions with respect to EPA's rule, "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Rule").

12. In preparing this declaration, I have reviewed the section of the Rule on pipelines and EPA's supporting documents, including the report from Los Alamos National Laboratory titled "CO2 Pipeline Analysis for Existing Coal-Fired Power Plants" (Apr. 11, 2024), the timeline spreadsheet prepared by ICF, and EPA's technical support document (TSD) "Greenhouse Gas Mitigation Measures for Steam Generating Units." EPA's Rule provides sufficient time to build a CO2 pipeline and meet a CCS-based emission standard

<u>EPA's pipeline cost and timeline analysis is reasonable</u>

13. I understand that EPA undertook analysis to determine how far each potentially affected power plant source is from a sequestration resource. This

analysis was conservative because it did not consider existing or planned CO_2 pipelines or sequestration opportunities in unmineable coal seams or oil and gas reservoirs.

14. The analysis was based on shorter, point-to-point pipelines connecting one source to one sink. The vast majority of these routes do not leave state lines. Shorter pipelines within state lines are generally less complicated and can be designed, permitted, and constructed on shorter timelines than long pipelines crossing state borders.

15. EPA's representative timeline in its technical support document allows for 12 months for feasibility studies, a 6-month gap, followed by 36 months for engineering, right-of-way acquisition, and permitting, and finally 18 months for construction.

16. This is a more generous timeline than the one provided in the ICF spreadsheet, which provides additional flexibility to accommodate potential project-specific challenges. The ICF timeline allocates 2.5 years for feasibility analysis, design, and permitting, broken down as follows: 1 year for feasibility analysis and design, 0.5 years for permit application preparation, and 1 year for permit issuance.

17. During my time at Battelle, we typically assumed a timeline of approximately 6 years from project initiation to operational status for single-source to single-sink commercial CCS projects. This timeline allowed for thorough

feasibility studies, engineering design, right-of-way acquisition, permitting, and construction. This phased approach was designed so that as costs went up over the phases, risk would go down. We used this as a conservative estimate, and it aligns with EPA's timeline.

18. Based on my professional experience in the field of carbon capture and storage, including pipeline planning and development, I find the ICF timeline to be reasonable and consistent with my understanding of typical project timelines.

19. EPA relied on several reputable sources in their analysis of the time it would take to design and construct and pipeline, including the ESPA Authoring Template, a Department of Energy review of CO2 pipeline infrastructure in the United States, a paper on lessons learned from CO_2 pipelines authored by IEA Greenhouse Gas R&D Programme (IEA GHG), the Global CCS Institute (GCCSI), and historical project timelines. These sources align with my experience referencing the best data available for forecasting timelines and provide a solid foundation for the EPA's analysis.

20. It is important to acknowledge that individual projects may encounter delays or challenges due to specific circumstances. However, the EPA's assumptions and timeline serve as a reasonable baseline for the purposes of this rule. I understand that in the case of obstacles or delays outside of the power company's control there are extensions and flexibilities available under EPA's rule.

<u>Near-term costs associated with building a pipeline to be operational in 2032 are minimal</u>

21. At Battelle, the way we conducted CO2 pipeline feasibility as part of a CCS feasibility study was quite simple, and very similar to the analysis EPA did to ensure the majority of regulated sources are within a reasonable distance to storage.

22. To perform the pipeline feasibility analysis, we would identify the location of the point source and perform high-level geology reconnaissance to locate the nearest sink capable of storing the necessary volume of CO2. We would perform rudimentary pipeline routing avoiding sensitive areas such as protected habitats, bodies of water and population centers. We would then perform a high-level cost estimate using publicly available transportation and storage cost data from DOE NETL, which includes basic engineering parameters.

23. The recent development of the Department of Energy's Carbon Capture and Storage (CCS) Pipeline Route Planning Database makes this process easier. The database is an open-source geospatial resource which provides considerations for routing pipelines from source to sink and is updated frequently. Considerations include state-specific regulations and restrictions, energy and social justice factors, land use requirements, existing infrastructure, and areas of potential risk. Careful planning and consideration of these factors early on should alleviate potential delays in the long run.

24. There are also companies that perform pipeline routing, feasibility and cost estimates. I was recently the lead project manager at Clean Air Task Force for multiple pipeline routing and optimization studies conducted by Carbon Solutions LLC.

25. One was a national assessment connecting up to 429 pollution sources to up to 146 geologic storage sinks and optimizing pipeline routes and avoiding urban areas, national parks, and other infeasible surface features, and performing multiple scenarios and providing economic analysis.[1] This project took less than a year at reasonable cost for a small non-profit, let alone a power company. This project was magnitudes more complicated than assessing the potential pipeline routes and costs for one power plant.

26. In fact, I later asked Carbon Solutions to perform a sensitivity connecting up to 216 sources with up to 99 sinks via an optimized pipeline and to provide total costs of capture, transport and storage, and the assessment was completed within weeks.

27. Given the EPA's compliance deadline of 2032 for a CCS-based emission standard, feasibility studies for pipelines would not need to commence until 2026. Furthermore, even under the EPA's conservative timeline outlined in

[1] Carbon Solutions, "National Assessment of Natural Gas Combined Cycle (NGCC) and Coal-fired Power Plants with CO2 Capture and Storage (CCS)" EPA-HQ-OAR-2023-0072-0893 (Sept. 2022).

the rule, which allocates 36 months for engineering, right-of-way acquisition, and permitting, these activities would not need to begin until December 2026 to meet the 2032 operational target. This provides ample time for power plants to assess their options, plan accordingly, and initiate the necessary steps to develop CO2 pipeline infrastructure in support of their CCS projects.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on June 10, 2024.

Benjamin Grove

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

State of West Virginia, et al, Petitioners, v. **Environmental Protection Agency, et al.,** Respondents.	Case No. 24-1120

<u>DECLARATION OF SUSAN HOVORKA</u>

I, Susan D. Hovorka, declare as follows:

1. I am a Senior Research Professor at the Bureau of Economic Geology at the Jackson School of Geosciences in the University of Texas at Austin, where I have been employed since 1981.

2. I received my Ph.D. in Geology from The University of Texas at Austin in 1990.

3. This declaration is submitted in support of Environmental and Public Health Respondent-Intervenors in their opposition to Petitioners' stay motions with respect to EPA's rule, "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From

Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Rule").

4. This declaration is based on my professional experience and expertise. I have reviewed EPA's determinations with respect to the geologic storage of carbon dioxide (CO_2) in EPA's supporting materials.

5. I have extensive experience and expertise related to the geologic storage of CO_2. I have published over fifty peer-reviewed articles on CO_2 storage siting and operations and have authored numerous book chapters and reports on CO_2 storage.

6. In 2004, I served as Principal Investigator for the landmark Frio Brine Pilot experiment, a pioneering field test of CO_2 injection. The project provided critical proof-of-concept and laid the groundwork for future scaled-up CO_2 storage efforts.

7. More recently, I was the lead author of a 2022 report that examined the investment needs and costs associated with characterizing potential CO_2 storage sites at various stages in the project development process.[1]

[1] Susan Hovorka, Taylor Barhart et al., *Early stage cost of storage characterization: Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies*, (Oct. 23-27, 2022), https://ssrn.com/abstract=4284960.

8. I also was a co-author of the Lawrence Livermore National Laboratory report *Roads to Removal: Options for Carbon Dioxide Removal in the United States*.[2] I contributed to that report's chapter on "Project-based Geologic CO_2 storage and cost assessment." The report was published in December 2023.

Process for and geographic availability of geologic sequestration

9. The field of geologic CO_2 sequestration has advanced rapidly from small-scale experiments to large-scale commercial operations. CO_2 injection and storage in deep geologic formations has a strong technical basis and has now been successfully demonstrated at about a hundred sites around the world. Significant experience has been gained in site characterization, modeling, monitoring, and risk assessment, enabling the safe and effective sequestration of millions of tons of CO_2 per year.

10. Geologic sequestration, when performed in properly characterized and selected storage reservoirs, can be expected with high confidence to contain the injected CO_2 for many thousands of years.

11. Risks associated with injection operations are well-understood and controlled by well-known engineering practices.

[2] https://roads2removal.org/.

12. Based on my review of EPA's supporting documents, "CO_2 Pipeline Analysis for Existing Coal-Fired Power plants," LA-UR-24-23321; "Technical Memorandum: Geographic Availability of CCS for New NGCC Baseload Units," EPA-HQ-OAR-2023-0072; and "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document," EPA-HQ-OAR-2023-0072, EPA's assessment of geological formations potentially amenable for CO_2 sequestration is consistent with the geologic science and aligns with the approaches used by the Department of Energy's National Energy Technology Laboratory (NETL) and the U.S. Geological Survey (USGS).

13. EPA describes potentially amenable formations as sedimentary rocks with layering and with sufficient injectivity to accept large volumes of CO_2. Injectivity is a function of the formation's thickness, permeability, depth, and pressure limitations. Potentially amenable formations must be deep enough for injected CO_2 to be isolated from fresh water and in a dense phase, and shallow enough to maintain adequate porosity for storage. This definition appropriately captures the key geologic characteristics necessary for secure and effective CO_2 sequestration.

14. In my experience developing the CO_2 Brine Database with the Gulf Coast Carbon Center, we employed similar criteria when assessing the suitability of formations for CO_2 storage. Our results defined many of the same potentially

amenable formations which have been augmented by data collected by further work sponsored by DOE's National Energy Technology Laboratory.

15. In the *Roads to Removals* report, using additional data and the same criteria, we concluded that almost half the land area in the United States is geologically prospective for CO_2 storage. Our findings are consistent with EPA's analysis.

16. According to EPA's analysis in its TSD for new NGCC units, 37 states have potentially amenable formations for geologic storage of CO_2.

17. Based on my professional experience and judgment, EPA's assessment of the geographic availability of potential geologic storage, as detailed in the rule and supporting technical documents, is robust and technically sound.

Schedule for development of geologic sequestration

18. The development of a sequestration site consists of several phases: a feasibility study, site location identification and assessment, detailed site characterization, permit preparation and submission and construction.

19. EPA reviewed prior CCS projects as well as an ICF sequestration site development schedule built based on relevant project timelines for characterization and development of injection and storage sites.

20. EPA's timeline estimates are realistic. Typically, to complete a CCS project, owner/operators would need to review the existing basin-scale potentially

amenable formations to identify one or more sites that are likely to be suitable for the project, screen them to remove sites that will not work for the project and invest further in those that are most favorable. Developers should plan for this process to take six years before planned operation of the project. Thus, to complete a project by 2032, it would be advisable to start the process no later than 2026.

21. Historical projects may have had longer timelines because they were first of a kind.

22. EPA's Class VI program builds on EPA's existing underground injection control (UIC) programs and the companies with UIC expertise have been providing technical support to Class VI project developers. Companies that historically have explored for and produced hydrocarbons also have been repurposing these skills to develop storage resources.

23. EPA relies on the NETL and USGS databases of potentially amenable formations. These serve as initial feasibility studies.

24. Storage site identification requires two additional steps: (1) site selection, wherein developers select one or more local candidate sites to be screened and (2) site characterization, wherein developers conduct detailed characterization of the down-selected candidates to prepare engineering designs and pipeline and injection permits.

25. Site selection requires assessment of availability of property rights required for storage and pipeline construction; assessment of relevant federal, state and local legal requirements for permitting all construction and operation; collection of existing geotechnical data; and evaluation and initial modeling to match project needs for injection to engineering designs.

26. Cost and timeline for site selection depend on amount of suitable existing data but range from less than 1 to 3 years.[3] A 3-year site selection process would be appropriate in instances where the area intended for sequestration had poor data. In that case, the core and seismic data to be collected as part of the site selection process would overlap with the site characterization stage.

27. Site characterization is then conducted for the selected site(s) to collect data needed to model the site response to CO_2 injection and engineer a suitable injection, risk reduction, monitoring, and closure program. Based on a survey of previous US site characterization, this may take 3 years.[4] The last year of this characterization program will include data collection and writing for permit preparation.

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[3] Hovorka, *supra* n.1.
[4] Susan D. Hovorka et al., Early stage cost of storage characterization, 16th International Conference on Greenhouse Gas Control Technologies, GHGT-16 (23rd -27th October 2022)

28. The ability of a formation to receive and contain CO_2 is not uniform. Finding a site in a geologic formation that is appropriate for injection may require characterization of more than one site. The number of candidate sites to be evaluated to identify one successful site varies depending on information available in each potentially amenable formation and the exploration skill of the team.

29. The area to be assessed for a given rate and duration of injection depends on the injectivity (thickness, permeability, depth, and pressure limits) of the storage formation. To accept larger rates of injection for longer periods of time requires adding more space, which can mean adding more formations vertically (stacked injection targets) or lateral space. Additional space can be either contiguous or in separate areas.

30. Storage basins with favorable injection properties have the benefit of increased injection rates per well which decreases drilling costs and the number of sites to which CO_2 must be delivered. Well spacing is determined by the formation injectivity as well as the injection rate and duration planned for each well. In a high-quality reservoir with good injectivity a large volume of CO_2 can be stored with a small number of wells.

31. Once a site is well-characterized, EPA's estimate providing 1 year for well construction is reasonable.

32. In summary, except in unusual circumstances, storage site development involves 1–3 years for the site selection process (which at the upper end overlaps with the first year of site characterization), plus 3 years for site characterization, plus 1 year for well construction, for a maximum of 6 years.

33. Given that timeline, a storage site intended to be operational by 2032 would not need to begin development until 2026.

<u>Conclusion</u>

34. Based on my professional judgment and experience, EPA has conducted a thorough and scientifically rigorous assessment of the feasibility, availability, and effectiveness of geologic sequestration of CO_2. The Agency has drawn upon a wide range of authoritative sources to demonstrate the availability of potential sequestration sites, the technical maturity of injection and monitoring techniques, and a reasonable timeframe for the development of these resources.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on June 5, 2024.

Susan Hovorka

Susan D. Hovorka

DECLARATION OF ANGELA NAVARRO IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

I, Angela Navarro, declare as follows:

1. I submit this declaration in support of Intervenors' opposition to the motions to stay the Environmental Protection Agency's final rule entitled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 8, 2024) ("Rule").

BACKGROUND AND QUALIFICATIONS

2. I am an energy regulatory attorney with nearly eight years of experience working across state government in the Commonwealth of Virginia. From 2015 until 2018, I served as Deputy Secretary of Natural Resources. The Office of the Secretary of Natural Resources oversees the natural resources agencies within the Commonwealth, including the Virginia Department of Environmental Quality. As Deputy Secretary, I led former Governor McAuliffe's policy work associated with climate mitigation, including working directly with the Virginia Department of

Environmental Quality on the state's Clean Power Plan implementation. I also worked to implement a number of Executive Orders and Executive Directives issued by Governor McAuliffe, including Executive Order 57 and Executive Directive 11, which initiated the Executive action to join the Regional Greenhouse Gas Initiative ("RGGI").

3. I then served as Deputy Secretary of Commerce and Trade under Governor Northam. The Office of the Secretary of Commerce and Trade oversees a number of commerce-focused agencies, including the Virginia Department of Energy. As Deputy Secretary, I led the work in support of the Governor's energy policy portfolio, including development of the Governor's Energy Plan and negotiation and implementation of the Virginia Clean Economy Act ("VCEA"). The VCEA sets forth the state's policy objectives on the transformation of the grid to cleaner energy resources, including via a renewable portfolio standard ("RPS") as well prescribing timelines for fossil fired power plant retirements.[1]

4. Finally, from January 2021 to February 2022, I served as one of three Commissioners on the Virginia State Corporation Commission ("SCC").[2] The SCC regulates, among other things, the vertically

[1] Virginia Clean Economy Act, HB 1526 and SB 851 (2020).
[2] Virginia Code § 12.1-2.

integrated investor-owned utilities ("IOUs") in Virginia. The SCC's scope of jurisdiction includes regulation of the rates, terms, and conditions by which the IOUs provide service to their customers.[3] The Commission also has regulatory oversight over the utility plans for compliance with the VCEA as well as the utility's long-term planning process, including consideration of environmental compliance costs, resource plans, and supply-side alternatives.[4] The Commission evaluates such plans, known as Integrated Resource Plans ("IRP"), through the lens of whether such plans are reasonable and in the public interest, evaluating factors such as the utility's load projections, anticipated generation portfolio, and environmental compliance obligations.[5] The Commission also develops and implements regulations to provide additional clarity on statutory directives. During my time on the Commission, I presided over several litigated dockets and rulemakings regarding implementation of the VCEA and consideration of long-term planning.

5. In preparing this Declaration, I have reviewed numerous documents, reports, and studies, including but not limited to: (a) the

[3] Virginia Code § 56-576 *et seq*.
[4] Virginia Code § 56-597 *et seq*.
[5] Virginia Code § 56-599.

Rule; (b) various EPA guidance documents related to the Rule's implementation; (c) the Motion to Stay filed by Petitioners State of West Virginia, *et al* ("Petitioners"); (d) the Declarations of Glenn Davis and Michael Dowd (collectively, "Virginia Government Declarants"); and thought-leadership pieces on the Rule from Harvard Law School.

6. Based on my prior role as Deputy Secretary to two Governors and as a Commissioner on the Virginia SCC, and my review of relevant materials, I have the personal knowledge and experience to understand the state of electricity generation within the Commonwealth of Virginia and within the PJM Interconnection region. I have deep knowledge of the steps the SCC will undertake in order to prepare for the Rule's implementation, including the long-term planning process, to ensure that Virginia's IOUs have reasonable plans in place to meet their reliability obligations.

<u>SCC Planning and Issues</u>

7. Virginia Government Declarants claim that the Rule will cause fundamental shifts in Virginia's energy markets in a way that will threaten the reliability of the grid. It is important to note that several policy and economic factors, which were underway well before

finalization of the Rule, are driving alternative economic dispatch and the retirement of less-economic coal fired power plants. These factors include low-price natural gas, the expansion of lower-cost renewable resources like solar, the passage of clean energy legislation in Virginia, and federal clean-energy incentive programs. These fundamental shifts began well before the adoption of the Rule.

8. Modeling in the Rule demonstrates that, compared to business as usual, the Rule will have little impact on the direction the electricity sector is moving in the Commonwealth. Virginia Government Declarants stress that the Rule will impact two coal-fired power plants in Virginia: the Virginia City Hybrid Energy Center ("VCHEC"), which is owned and operated by Dominion Virginia Power ("Dominion"), and the Clover Power Station, which is co-owned by Dominion and Old Dominion Electric Cooperative. However, in Dominion's most recent IRP, the company projected that VCHEC is not economic to operate based on a 10-year cash flow analysis, which is typically the central consideration on utility retirement decisions.[6] The net present value ("NPV") for VCHEC under Plan A, which is the plan that "allowed the model to select

[6] Case No. PUR-2023-00066, In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Integrated Resource Plan of Virginia Electric and Power Company at p. 83.

the retirement dates for existing units on a least-cost optimization basis" reveals that VCHEC's NPV over the 10-year cash flow analysis is negative $199 million.[7] For Clover Units 1 and 2, which are the two additional units Virginia Government Declarants identified for retirement, these units face a negative NPV under at least one scenario, the "Low Capacity Price" scenario.[8] Per the IRP, "[a] positive NPV result indicates that the unit is currently better than market, while a negative value indicates the unit is currently worse than market."[9]

9. Based on my experience with Virginia's electricity sector, it is incorrect to conflate the Rule's limited impact on the expected trajectory of unit retirements with the aforementioned general trends in the electricity sector that are leading such units to be uneconomic to operate. Virginia Government Declarants claim that the planning activity to address potential coal retirements should be attributed solely to the Rule. But it is my experience that planning for federal GHG emissions has been a central component of the IRP analysis since the first iteration of carbon regulation under Section 111 nearly a decade ago. Virginia Code already

[7] *Id.*
[8] *Id.*
[9] *Id.* at p. 82

directs the utilities to embed modeling to assess the impacts of federal environmental regulation, which the utilities have done and will continue to do annually via the IRP and IRP Update process. For example, Virginia Code directs the IOUs, in preparing their IRP, to systematically evaluate "[t]he effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities."[10] Furthermore, Virginia Code directs the IOUs to "conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan."[11] These planning documents are iterative, and it is my experience that the utilities continue to model and plan for federal GHG compliance, just as they have done in their IRPs and IRP Updates every year for nearly a decade.

10. Additionally, Virginia Government Declarants claim that the Rule's two-year time frame does not provide an opportunity to develop innovative state plans. In my opinion, the significant electric planning

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[10] Va. Code § 56.599(B)(8).
[11] Va. Code § 56-599 (C).

work discussed herein demonstrates that Virginia's IOUs are fully capable of integrating a shifting generation mix into their IRP process in a way that models compliance in a least cost, reliable manner within the Rule's timeline. For example, the SCC directed Dominion to present a "least cost plan" that models many factors, including compliance with carbon regulations and VCEA requirements, in its future IRP.[12] The IOUs have utilized this IRP process to model compliance alternatives (including retirements) for a variety of federal and state regulations in the recent past. For example, Dominion's 2018 IRP reflected the final retirement of Yorktown 1 and 2 after incorporating the EPA's Mercury and Air Toxics Standards, where such retirements were modeled and reviewed by the SCC in the 2016 IRP.[13] As such, the SCC has extensive history reviewing these plans and providing direction to the utility as it develops alternative scenarios for compliance to ensure that such planning is done in a low cost and reliable manner.

11. Additionally, Virginia has a robust, multilayered system to maintain electric reliability that will continue to serve the state's

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[12] Case No. PUR-2020-00035, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Final Order February 1, 2021 at p 14 (While this Order was issued during my first month as a Commissioner, I did not participate in this docket).

[13] *See* Case No. PUE-2016-00049, Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan, at p. 49.

electricity consumers during implementation of the Rule. Virginia Code directs the IOUs, in preparing their IRPs, to identify a portfolio of electric generation assets that "is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term." Furthermore, in the SCC's final Order on Dominion's 2020 IRP, the Commission directed the utility "to include in future IRPs and updates the up-to-date reliability analyses of the impacts of retiring traditional fossil generation and adding growing amounts of renewable energy resources on the Company's electric system."[14] The Commission directed this analysis in response to Dominion's projected coal plant retirements as prescribed under the VCEA and such retirement analysis could address the Rule as well. Furthermore, Virginia is a member of PJM Interconnection, which works with the state in planning and maintaining the reliability of the electric grid. PJM assists with reliability by, among other things, monitoring the transmission system and assuring compliance with the

[14] Case No. PUR-2020-00035, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Final Order February 1, 2021 at p. 9 (While this Order was issued during my first month as a Commissioner, I did not participate in this docket).

national reliability standards approved by the Federal Energy Regulatory Commission ("FERC"). In addition, PJM maintains a forward-looking capacity market that is designed to ensure sufficient generating capacity is available to meet demand several years in advance. These overlapping institutions and processes are designed to preserve reliability going forward under all reasonable scenarios, including implementation of the Rule.

12. In my experience, planning for the Rule would not require burdensome coordination among state agencies, as such interaction among agencies is already routine. The SCC and DEQ initiated coordination on federal GHG regulations in 2015 when they were first proposed, and the systems for collaboration remain in place on a wide range of issues, including around implementation of the VCEA. The SCC is also in frequent communication with PJM regarding reliability, load forecasting, and expected transmission-system constraints. There are also strong, ongoing working relationships among public utility commissioners in the region, facilitated by organizations such as the Organization of PJM States, Inc. ("OPSI") and the Mid-Atlantic Conference of Regulatory Utility Commissioners ("MACRUC"). Thus, the

Rule will not require significant additional coordination beyond what is already happening in the state and region.

13. Moreover, the Rule will likely not require significant new Commission resources and expertise to perform its regulatory functions. As noted extensively herein, reviewing the IOUs plans for compliance with Clean Air Act rules is already part of the Commission's oversight of long-term planning. As such, my experience is that the Commission already has staff in place with expertise on these items, and the Rule will not require additional cost or resources. Foundationally, the planning and preparation for compliance with the Rule is similar to the utility planning process that already occurs on an annual or biannual basis in the Commonwealth.

Conclusion

14. Based on my experience as a former Commissioner on the SCC, and as a senior policy advisor to two governors, many of the Virginia Government Declarants' concerns can readily be addressed within the current utility planning process prescribed in state law and regulation within the Rule's timeframe. Their declarations underestimate the ability of the Commission to adjust its review of IOU's long-term plans to

incorporate environmental requirements, such as those in the Rule. There is an extensive system in place to address the very issues that Virginia Government Declarants maintain will be infeasible, and that system is designed to ensure that Virginia's IOUs maintain the reliability and affordability of the grid. Energy regulators in Virginia consistently, effectively, and efficiently administer their duties and will continue to do so.

I, Angela Navarro, declare under penalty of perjury that the foregoing is true and correct. Executed this 7th day of June, 2024.

Angela Navarro

Angela Navarro

DECLARATION OF RIC O'CONNELL, MICHAEL O'BOYLE, AND BRENDAN PIERPONT IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

We, Ric O'Connell, Michael O'Boyle and Brendan Pierpont, jointly declare as follows:

Qualifications

1. I, Ric O'Connell, am the Executive Director at GridLab, a nonprofit organization that provides expert capacity and thought leadership to address technical challenges as the grid transitions to clean energy. I have performed numerous studies on power systems reliability, renewable energy integration, project economics, and transmission planning for over 20 years. I have significant professional experience with modeling future power systems, and have published many widely read reports and analysis on current and future power systems. I was an executive and engineer at Black & Veatch for 12 years, where I performed engineering design and diligence on dozens of utility scale solar projects, and assisted several utilities with planning and procuring new resources. In 2005 I earned a Masters in Science from the University of Colorado, Boulder, and in 1990 I earned a Bachelor of Science in Electrical Engineering from Duke University.
2. I, Michael O'Boyle, am Senior Director, Electricity at Energy Innovation, LLC, a non-partisan energy and climate policy think tank that produces independent analysis to inform policymakers of all political affiliations in the world's largest emitting regions. We provide objective, science-based research to policymakers and other decision-makers seeking to understand which policies are most effective to ensure a safe climate future. Our work includes conducting quantitative assessments of how our energy sectors will change as the world moves toward a zero-carbon economy, using those quantitative

assessments to inform policy priorities and policy ambition, and researching lessons about detailed policy design and implementation. We prioritize emissions reduction policies in the largest-emitting nations and largest-emitting sectors, with a focus on policies that accelerate markets for technology-neutral zero-carbon solutions at the speed and scale science says is necessary to confront the climate challenge, while delivering economic, security, and equity benefits. All our recommendations stem from careful research and analysis. I have researched power system transformation at Energy Innovation for 10 years, leading a team to analyze energy policy impacts with a focus on the U.S. electricity sector. We use these insights to publish research and make independent recommendations to policymakers on the policy design to achieve a rapid, affordable, reliable transition to a low-carbon economy. I have published dozens of research reports focused on utility regulation and energy system optimization, several of which have been entered into peer-reviewed journals. I have co-authored studies that use industry-standard system planning and dispatch models to analyze least-cost pathways to reduce emissions from the U.S. grid and have become familiar with the operation and design of these models. I've also contributed the power sector chapters to Energy Innovation's 2018 publication, "Designing Climate Solutions." I have given numerous presentations on regulatory topics and resource economics at state public utilities commissions, including Minnesota, Nevada, Oregon, and Rhode Island, as well as at National Association of Regulatory Utility Commissioners convenings. I have facilitated substantive conversations between utility regulators and industry experts on energy transition, rate design, market design, and financial topics. I am familiar with the technologies, economics, development dynamics, financial incentives, and regulatory environment in which electricity markets

operate. I also studied utility regulation pursuing my Juris Doctorate at Arizona State University and was accepted into the Arizona Bar Association in 2014.

3. I, Brendan Pierpont, am Director of Electricity Modeling at Energy Innovation, LLC. I have conducted expert research and analysis of electricity market and policy issues and have over 15 years of experience modeling the economics of electricity sector resources, evaluating utility resource planning analyses, and analyzing electricity sector data and trends. I have authored research reports on electricity sector policy and market issues and have drawn on my expertise to provide research and analysis to policymakers, market participants, and public interest stakeholders. I am familiar with utility integrated resource planning processes and recent plans filed by utilities around the country. I am also familiar with sector-wide electricity trends and the economic forces shaping those trends. I have studied electricity market design, electricity resource adequacy and reliability, coal power plant economics and the economics of power plant pollution control regulation. In 2015 I earned a Master's degree in Management Science and Engineering from Stanford University, with a focus on energy system modeling and analysis.

4. We have reviewed the U.S. Environmental Protection Agency's ("EPA's") rules titled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 9, 2024) (the "Rules") and are familiar with their requirements.

Summary of Declaration

5. Our declaration focuses on four facts.

- First, coal economics have been worsening, and as a result coal use in the electricity sector has been rapidly declining since the late 2000s. The aging fleet of coal plants affected by the Rules is increasingly uneconomic and a significant portion of the fleet is likely to retire even without the Rules.
- Second, utilities are unlikely to make significant, irreversible investments in response to the Rules in the next two years. Most of the immediate utility actions under the Rules would be to plan, evaluate, and begin soliciting competitive bids from market participants for replacement generation or retrofit of existing coal units. In the case near-term investments are necessary, they likely do not harm consumers or utilities, due to the nature of utility ratemaking and the cost savings possible from clean replacement, gas co-firing, and retrofits.
- Third, the Rules' compliance timelines give utilities more than enough time to plan for retirement, if they choose that route, by contracting with, developing, and interconnecting new generation resources sufficient to replace those plants.
- Fourth, utilities, regional grid operators, and their regulators have adequate solutions to maintain electric system reliability both in the short-term and in the long-term during implementation of the Rules.

Section 1: Coal use in the electricity sector is rapidly declining, as the aging fleet of coal plants is increasingly uneconomic.

6. The use of coal in the U.S. electricity sector is in the midst of a long-term sustained decline. Coal has decreased from 45 percent of U.S. electricity generation in 2010 to 16 percent in 2023.[1] Of the 342 gigawatts (GW) of coal-fired capacity operating in 2010, 136 GW has retired, and 24 GW of capacity has stopped burning coal as a primary fuel, leaving only 192 GW of currently operating coal-fired power plants.[2]

7. While most coal plants were originally designed to operate as "baseload" resources that operated nearly all the time, this type of operational profile is no longer economically justified as resources with lower operating costs are now available for many hours of the year. As a result, coal capacity factors (the proportion of a plant's average electricity generation to that plant's available generating capacity) have declined significantly over time. The fleet-wide average coal capacity factor has declined from 67 percent in 2010 to 42 percent in 2023, with continued declines in the first quarter of 2024.[3] Even with this decline in utilization, many coal plants still operate at times when their variable costs of operating are greater than the market price for the energy they produce. Since 2015, uneconomic coal plant operations have cost electricity customers $17.8 billion more than the value of energy at market prices during those hours.[4]

8. This decline of coal-fired electricity generation is mirrored by a significant reduction in coal mining volumes and coal mine closures, raising fuel supply

[1] EIA, "Electric Power Monthly", https://www.eia.gov/electricity/monthly/
[2] Capacity reflects "Nameplate" capacity rating of generating units. Current capacity includes additions since 2010. Based on analysis of EIA Form 860 data.
[3] EIA, "Electric Power Monthly", https://www.eia.gov/electricity/monthly/
[4] RMI, "Economic Dispatch Dashboard," https://utilitytransitionhub.rmi.org/economic-dispatch/

risks for coal-fired power plants.[5] The decline in coal production directly impacts the considerations of electricity generators. For example, in their 2023 Carolinas Resource Plan filing with regulators in North Carolina and South Carolina, Duke Energy states that delaying coal retirement timing into the mid to late 2030s would mean deteriorating supply conditions for fuel, which would "create future risks for coal supply assurance and ultimately increase reliability and cost risks for customers."[6]

9. Many coal-fired power plants are aging. The average coal plant was built 43 years ago, and by 2032 the average plant will be over 50 years old.[7] As coal-fired power plants age, they become more expensive to operate and maintain. Operations and maintenance costs are roughly 20 percent higher for coal plants between 40 and 80 years old, compared with those between 20 and 40 years old.[8] These high fixed costs, combined with falling utilization and increasingly flexible operations, make many of these plants uneconomic to continue operating relative to other generation resources.[9]

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[5] According to EIA data, from 2010 to 2023, coal production in the U.S. fell from 1.1 billion short tons to 0.6 billion short tons. While nearly 1,200 coal mines reported active coal production in 2010, by 2022 over half of these were no longer producing coal.

[6] "For Duke Energy, any delays in coal retirement timing, particularly if plant operation is extended into the mid and late 30s, would most likely result in the need for continued coal supply after the coal industry has reduced thermal coal production in response to the utility industry's continued transition away from coal generation. Access to the commodity, the reagents utilized to treat emissions resulting from use of the commodity and transportation have high potential to deteriorate or disappear. These declines in supply availability and market uncertainty create future risks for coal supply assurance and ultimately increase reliability and cost risks for customers. For these reasons, it is extremely important that the Companies plan and execute an orderly energy transition." Duke Energy, "Carolinas Resource Plan: Chapter 1," p. 10. https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-1-changing-energy-landscape.pdf

[7] S&P Global, "Inflation Reduction Act to accelerate US coal plant retirements," Feb 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/inflation-reduction-act-to-accelerate-us-coal-plant-retirements-74196498

[8] Sargent and Lundy, "Generating Unit Annual Capital and Life Extension Costs Analysis," December 2019, https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent and Lundy further found that annual operations and maintenance plus ongoing capital investment totaled $87 per year per kW of capacity for plants over 40 years old, in today's dollars.

[9] NARUC, "Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices", 2020, https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45

10. Coal faces increasing economic pressure from other generation sources, primarily wind, solar, battery energy storage, and natural gas. The average cost of utility-scale solar power purchase agreements has fallen over 85 percent between 2009 and 2022[10] and wind power purchase agreements have fallen in cost by over 60 percent.[11] Likewise, the cost of lithium ion battery packs has fallen by over 80 percent in the last 10 years.[12] In 2022, the Inflation Reduction Act (IRA) extended and expanded tax credits for solar, wind and energy storage, driving further cost reductions for new projects. Research from Energy Innovation found that 99 percent of operating coal plants are more expensive to run compared with the cost of new wind and solar generation.[13] Low natural gas fuel costs and improvements in gas turbine efficiency have put further economic pressure on coal-fired power plants over the last decade.

11. Coal's decline is highly likely to continue. Out of the 192 GW of coal plants that remain online today, 36 percent have announced plans to retire or cease burning coal by the end of 2030 or sooner.[14] Estimates from the U.S. Energy Information Agency (EIA), National Renewable Energy Laboratory (NREL), and S&P Global Market Intelligence project coal will account for only 5-10 percent of U.S. electricity generation by 2030, down from 16

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[10] Berkeley Lab, "Utility-Scale Solar, 2023 Edition", October 2023, https://live-etabiblio.pantheonsite.io/sites/default/files/utility_scale_solar_2023_edition_slides.pdf

[11] Berkeley Lab, "Land-Based Wind Market Report: 2023 Edition," August 2023, https://emp.lbl.gov/sites/default/files/emp-files/land-based_wind_market_report_2023_edition_final.pdf

[12] BNEF, "Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh," November 2023, https://about.bnef.com/blog/lithium-ion-battery-pack-prices-hit-record-low-of-139-kwh/

[13] Energy Innovation, "Coal Cost Crossover 3.0," https://energyinnovation.org/publication/the-coal-cost-crossover-3-0/

[14] Sierra Club data shows 122 GW of coal remain without plans to retire or cease burning coal through 2030. Sierra Club, https://coal.sierraclub.org/campaign

percent in 2023, with declines driven by economic pressure from lower-cost clean energy sources.[15]

12. In light of these trends, prudent utility practices would include evaluating the economics of continued operation of coal-fired power plants relative to alternatives. In fact, many utilities have already undertaken this type of analysis and developed plans to fully exit coal by 2032 or sooner.

Section 2: Undertaking activities to consider, plan, and procure alternatives is prudent utility practice.

13. Recent changes in technology cost and tax incentives mean that utilities should be evaluating alternatives to their coal generation fleet to serve their customers at least cost irrespective of EPA rules.[16] Those planning exercises take between one to two years, including internal planning, public comment on proposals, and then requests for bids from generators and other technology providers to meet the system needs identified. These planning costs fall in the normal course of business, and utilities can generally recover prudently incurred costs of these planning and procurement processes. Further, those minimal costs would not result in higher electricity rates at a level that would harm state economies.

14. Even in the unlikely case substantial replacement or retrofitting capital expenditures are necessary under the Rule in the very near term, harm remains highly unlikely if utilities allow planning to reveal the least cost

[15] See for example: NREL, "2023 Standard Scenarios: Mid-Case Current Policy Scenario", https://scenarioviewer.nrel.gov/
EIA, "2023 Annual Energy Outlook," https://www.eia.gov/outlooks/aeo/
S&P Global, "Inflation Reduction Act to accelerate US coal plant retirements," Feb 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/inflation-reduction-act-to-accelerate-us-coal-plant-retirements-74196498

[16] See generally, https://www.analysisgroup.com/globalassets/insights/publishing/2024-electric-utilities-and-the-ira-iija.pdf

option, especially for existing coal-fired power plants without firm retirement dates before 2032.

Over the next two years utilities would only be planning for emissions controls or replacement power, not investing significant amounts of capital. Most utilities undertake this type of planning exercise as part of their normal course of business.

15. Utility rates only change when utilities apply to their regulators or board for review and approval of that change in a rate case. The rate case is a petition to change rates based on projected changes to expenditures. An investment in technology, whether carbon capture and storage (CCS), co-firing, or in a replacement portfolio would not go into rates until expenditures are approved and begin. The costs associated with resource planning and structuring market bids are minimal in the magnitude of the revenue requirement and would not be felt by customers, and likely would not even require a rate case to cover these costs, which are incurred as a regular course of business regardless of the Rules. It would not be necessary to incur large capital expenditures associated with compliance in the next two years.

16. Resource planning is a process that utilities undertake periodically, especially when considering major investments, to determine what is the best option for their customers and business. Most customers are served by utilities whose plans must be approved by state regulators, and cooperatives, municipal utilities, and federal power administrations also have boards that serve a similar function. A utility best practice is integrated resource planning, through which all cost-effective options are meant to be examined over a 10 to 20-year time horizon and subjected to public comment and regulatory approval. Integrated resource plans take less than a year for

utilities to develop internally, then about a year to present, negotiate, and finalize through a public process.

17. We've collectively worked with stakeholders in over three dozen integrated resource planning proceedings over the last five years, and we understand that the modeling and analysis necessary to inform a least cost planning exercise can be done relatively quickly thanks in part to modern computing. GridLab has routinely completed modeling exercises to correct outdated assumptions and promote modern modeling techniques in a matter of months to support a better outcome for consumers, public health, and climate pollution. For utilities, re-running their models with updated assumptions to understand the least cost compliance pathways is feasible, and is a routine cost associated with ongoing planning.

Investment and spending on compliance does not harm electric utilities themselves, or state economies through rate increases, which modeling and analysis have shown are unlikely or minimal.

18. Rising coal costs; low natural gas costs; and falling costs of wind, solar, and storage has already made it prudent for every utility to reassess the economics of running coal past 2032. The rule stimulates this economic evaluation process for utilities that have not examined such alternatives publicly, which is very unlikely to increase rates or harm utilities' businesses over the next two-year period. Furthermore, publicly available data and market trends strongly suggest that this would likely result in lower overall costs to the vast majority of utilities and ratepayers.

19. Though best practice is to plan and optimize under regulatory and public procedure to illuminate least cost solutions to compliance, some utilities may act more quickly and begin investing within the next two years. But

capital expenditures to replace or retrofit old coal plants do not mean rates will increase.

20. Rates are impacted by both the scale of up-front investment, as well as the overall impact on utility costs over the long-term, including savings associated with lower fuel costs or additional CCS-related revenue. New capital expenditures like CCS, co-firing, or replacement generation are not recovered from customers in one lump sum. Any addition to the capital base is collected annually at a rate that reflects the useful life of the asset, plus returns that cover the cost of capital. The degree of cost impact relative to the existing capital base also matters. Generation, the portion of utilities' assets affected by the Rules, accounted for only 26 percent of investor-owned utilities' functional capital expenditures in 2023, with the rest tied up in distribution and transmission.[17]

21. For utilities specifically, new investments are likely a benefit. Monopoly utilities charge their customers the cost of serving them, including the returns required to raise debt and equity capital as applicable. For-profit investor-owned utilities, such as members of the Edison Electric Institute, must submit rate requests for approval by state regulators while municipal, cooperative, and federal utilities have some version of boards that serve a similar function. For-profit utilities see higher returns for shareholders when they increase their capital expenditures under this regulatory framework.[18]

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[17] EEI, 2023. Capital Expenditures Summary. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/bar_cap_ex.pdf.

[18] See generally, Steve Kihm et al. *You Get What You Pay For: Moving Toward Value In Utility Compensation, Part 1 – Revenue & Profit*. 2015. https://energyinnovation.org/wp-content/uploads/2014/12/CostValue-Part1-Revenue.pdf

22. Coal plants have a large operational cost in the form of fuel purchases as well as operating expenses like labor.[19] While capital expenditures operate like a sunk, fixed cost on consumer bills, lower coal use immediately leads to a reduction in operating costs. Assuming flat or growing demand for electricity, reductions in coal use would be replaced by new costs in the revenue requirement, with potential savings from cheaper replacement or higher costs from more expensive replacement. Higher rates would only occur if the levelized expenses from replacement or retrofit exceed the savings from burning less coal and/or retiring the plant.

23. Prudent utility planning for least cost compliance would likely reveal many options to avoid large rate increases and even achieve immediate savings when faced with these choices, with especially minimal impacts in the near term. For the plants which have not currently announced retirement dates before 2032, considering and investing in replacement resources does not necessarily result in harm to utilities, their customers, or state economies. In fact, it can be good for economies, utility companies, and customers.

24. A 2023 report by Energy Innovation, the Coal Cost Crossover 3.0, found that after the passage of the Inflation Reduction Act and due to continued cost declines of wind and solar, 99 percent of U.S. coal plants were in 2021 more expensive to simply run than the all-in levelized cost of new local or regional wind and solar power.[20] In ratemaking terms, the all-in cost of wind

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[19] While some utilities own coal plants in part or in whole, utilities can also contract on behalf of their customers for energy from coal plants owned by other utilities or independent power producers. Contracts for energy are generally also treated as operational expenditures and roll off the utility balance sheet completely when they expire. In the case of utility cooperatives, contracts between distribution cooperatives and generation and transmission cooperatives (G&T) are symbiotic and function like a sunk cost – the G&T will typically make investments in power plants only when its members agree to cover those costs and take energy from those plants over a period long enough to justify the expense.

[20] Michelle Solomon, Eric Gimon, and Mike O'Boyle. *The Coal Cost Crossover 3.0*. Energy Innovation. 2023. https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

and solar power to provide 100 percent of the annual energy of the coal plants examined would be lower than the operational costs and going-forward capital costs of virtually all coal plants.

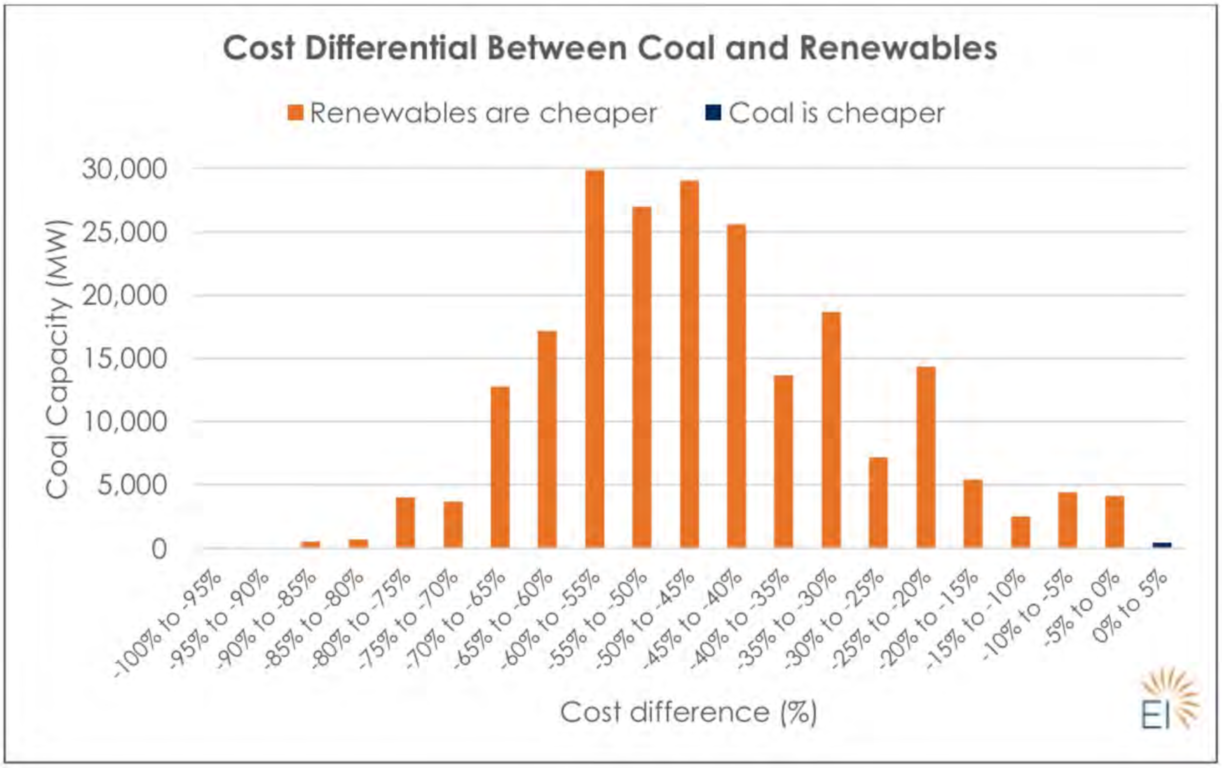

Figure 1. Aggregated plant capacity shown as percent difference between renewables levelized cost of energy (LCOE) and coal going-forward cost. The orange bars indicate capacity where renewables are cost-competitive with coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

25. Furthermore, coal is not necessary for the reliability attributes it provides. As we discuss in Section 4 below, reliability is a system attribute, and coal does not need one-to-one replacement to ensure the system remains reliable. Because wind and solar are so much cheaper than coal in many parts of the country, these operational savings can be used to pay for complementary resources with high reliability value like battery storage, interregional

transmission, or combustion turbines, often at a savings or minimal ratepayer cost.

26. The Coal Cost Crossover analysis finds the operational savings from switching from coal to wind and solar energy are enough to cover a large portion of the storage costs necessary to make wind and solar just as dependable and dispatchable as coal, again without necessarily raising customer costs. Energy Innovation's Coal Cost Crossover report evaluates the amount of storage capacity that can be financed based on the cost savings from replacing coal with wind and solar, and compares that storage capacity to the capacity of the coal plant. We found that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants (65 percent of existing coal capacity). While this analysis reflects 2023 costs, storage costs will likely continue to drop over the next eight years and beyond.[21] New low-capacity-factor natural gas combustion turbines, energy efficiency, and demand response should also be considered as part of an analysis of the least-cost portfolio to replace a coal-fired power plant.

27. Additional savings are possible through good policy design that optimizes customer payments for the stranded coal costs (if applicable) as well as transmission infrastructure associated with replacement projects. On the financial side, though past capital expenditures on the coal plant remain in the revenue requirement until full depreciation, there are opportunities to leverage creative low-capital-cost financing to reduce the total rate impact of

[21] Wesley Cole and Akash Karmakar, Cost Projections for Utility-Scale Battery Storage: 2023 Update. National Renewable Energy Laboratory. 2023. https://www.nrel.gov/docs/fy23osti/85332.pdf

repaying stranded capital investments, including securitization.[22] The analysis also considers some aspects of transmission access relevant to a cost analysis by examining the economics of wind and solar projects within a 45 kilometer radius, finding 199 of the 210 plants still had cheaper replacement options with these locational constraints applied. Clean portfolios of wind, solar, and storage could be installed at existing coal sites, facilitating an even faster, lower cost interconnection and replacement process.[23]

28. For those coal facilities assessing a CCS retrofit, again the full long-term ledger has to be taken into account to assess ratepayer and state economic impacts. In its Rulemaking, EPA provided evidence that on average, CCS plants capturing 90 percent of emissions save customers money after installation because of IRA tax incentives that offer a marginal benefit to consumers of more than $100 per megawatt-hour. Recent government studies of CCS feasibility support this claim.[24] Any effort to install CCS at the state or utility level will be the result of least-cost planning and, if so, will have been selected with this full range of costs and benefits considered.

29. Assessment of natural gas co-firing or full conversion should involve a similar examination of the whole revenue requirement. Additional investments that enable the plant to operate on natural gas should also be measured in conjunction with changes in fuel cost, and the hedging, flexibility, and resilience value that dual fuel operation may provide. For example, a report from Andover Technology Partners submitted to the

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[22] See generally, Ron Lehr & Mike O'Boyle, Managing the Utility Financial Transition from Coal to Clean. Energy Innovation. 2018. https://energyinnovation.org/wp-content/uploads/2018/12/Managing-The-Utility-Financial-Transition-From-Coal-To-Clean.pdf.

[23] Katie Siegner, Alex Engel. *Clean Repowering: A Near-Term, IRA-Powered Energy Transition Accelerant*. RMI. 2024. https://rmi.org/clean-repowering-a-near-term-ira-powered-energy-transition-accelerant/

[24] https://netl.doe.gov/projects/project-information.aspx?p=fe0031845

record indicates that "natural gas co-firing is advantageous for load following"[25] as compared to only firing coal. Given that the average coal-fired plant operated at roughly a 42 percent capacity factor in 2023[26] and has since fallen, coal is now, and will increasingly be asked to serve this load-following function. The Andover report pegs the incremental capital cost of gas co-firing at around $50 per kilowatt (kW), or about 1-2 percent of the original cost of the plant.[27] The report also highlights examples of co-firing for a range of reasons, including resilience, access to cheaper fuel, and reduced environmental remediation costs. Thus, any costs from implementing this compliance option would be minor, and most of these costs would not occur in the next two years.

Section 3: The timelines for replacement power are sufficient to plan, procure, build, and interconnect resources necessary to maintain a reliable grid under the EPA rule.

30. As covered in the previous section, the main utility activities under this Rule in the next two years will be related to planning. In this section, we provide detailed evidence to demonstrate that if an existing coal plant operator chooses to retire and replace its generation, there is ample time to plan, study, procure, and develop a replacement clean energy portfolio such that significant expenditures and reliability issues would not manifest over the next two years, or even by 2032.

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[25] Andover Technology Partners. Natural Gas Cofiring for Coal-Fired Utility Boilers. Commissioned for CAELP. 2022. at p. 7. https://www.andovertechnology.com/wp-content/uploads/2022/02/Cofiring-Report-C_21_2_CAELP_final_final.pdf

[26] EIA data.

[27] There are likely additional costs associated with pipeline construction, which the EPA examined in its Unit-Level Cost and Reduction Estimates for Natural Gas Co-Firing Final Rule. These must be measured against projected fuel costs, and consideration of depreciation schedules must also be taken into account.

31. For utilities that choose to comply with the rule by retiring coal plants and replacing them with cleaner portfolios, the rule requires compliance by 2032, or about seven and a half years from when the rule enters force in July 2024. Projects in the interconnection queue today can be helpful – utilities are not starting from a standstill when looking to develop new projects. Aggregated data from regional "interconnection queues" suggest that ample resources are shovel-ready to replace coal generation on an expedited timeline. While the time to get through this queue has increased over time, so have the interconnection agreements already approved. Currently, 311 GW of resources in the queue have either drafted or completed their interconnection agreements, signaling they are ready to execute contracts and begin commercial development, according to a Lawrence Berkeley National Laboratory (LBNL) study published in 2024.[28] Around 300 GW of additional wind, solar, storage, and gas resources are in the final study stage, the facility study, which the Federal Energy Regulatory Commission (FERC) estimates takes 90-180 days.[29]

32. Considering 861 projects across six regional grid operators, the LBNL study found that the average project from 2016-2023 reached commercial operation an average of 25 months after interconnection agreement execution, with moderate regional variability outside of the California Independent System Operator (CAISO).[30] In other words, several hundred GW of projects can likely reach commercial operation within the next three years.

[28] Rand et al. *Queued up: 2024 Edition*. Lawrence Berkeley National Lab. 2024. https://live-etabiblio.pantheonsite.io/sites/default/files/queued_up_2024_edition_r2.pdf

[29] Rand et al., 2024.

[30] LBNL's dataset did not have data for the non-ISO regions, the West and Southeast, but specific utility timelines back up the national LBNL dataset for utilities in these regions as well. Because California utilities already are coal-free and not planning on building new gas, this timeline analysis does not apply to them.

33. The queue data shows there are hundreds of gigawatts of electric generation capacity, spread relatively equally between major grid regions, that either currently or will soon complete their interconnection agreements, and therefore will be available for procurement and operation an average of two years from now. For reference, fewer than 200 GW of coal plants are online today. The precise amount of replacement resources available under current and pending interconnection agreements will vary from region to region, but the sheer magnitude of projects already completed demonstrates that utilities can replace coal as new resources are brought online. Each regional market examined by LBNL is replete with resources that have completed the technical requirements to enter into operation much sooner than 2032.

34. Over the next year, two recent FERC rules will take effect and further reduce barriers to rapid deployment of cost-effective replacement resources. FERC Order 2023 required regional grid operators and utilities to modernize their interconnection study procedures and finish them more quickly or face fines. These rules will reduce the incremental cost of interconnection for new resources and promote transmission investments that facilitate larger batches of resources to connect. FERC Order 1920 requires regions to update their regional transmission planning practices to consider an expanded set of consumer benefits and account for the economic benefits of new generation options as well.

35. For an example of how utility planning and procurement works in practice, the Northern Indiana Public Service Company (NIPSCO), which serves 480,000 electricity customers in Northern Indiana and is in the Midcontinent Independent System Operator (MISO), completed its integrated resource plan in 2021. It expects to cost-effectively bring 400 megawatts (MW) of wind capacity, 1,485 MW of solar capacity, and 135 MW of storage capacity

online by 2025 to replace aging coal plants – a matter of four years.[31] NIPSCO has set a target of zero coal-fired generation by 2028, compared to 75 percent of the utility's generation mix from coal in 2018.

36. Specific utilities outside of the independent system operator (ISO) regions have also managed to plan for coal retirement and replacement in far fewer than seven and a half years. For example, Duke Energy Carolinas' recent 2023 request for proposals (RFP) for new solar and storage will take an estimated 14 months, and requires respondents to enter service "within three years following the end of the contract phase," a total just over 4 years after planning concluded.[32] The 2022 RFP of Tri-State, a large generation and transmission cooperative utility in Colorado, New Mexico, Nebraska, and Wyoming – the output of a two-year planning and settlement process – also required procurement to replace retiring coal generators for "projects with commercial operation dates on or before December 31, 2025 . . . [and may consider] highly competitive bids with commercial operation dates in 2026."[33] This process will procure sufficient resources in a four-year period to replace multiple large retiring coal plants. In 2021, Public Service Company of New Mexico issued RFPs for a resource portfolio to replace its retiring coal-fired San Juan Generating Station, requiring "a planned project in-service date of no later than December 31, 2024."[34] In June 2024, Entergy

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[31] 2024 NIPSCO Integrated Resource Plan, First Stakeholder Meeting Presentation. April 23, 2024. https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/presentation-april-23-2024.pdf?sfvrsn=8fd3e151_9.

[32] Duke Energy Carolinas, 2023 Solar and Storage Paired with Storage Procurement: Request for Proposals for New Solar Resources. 2023. https://www.dukeenergyrfpcarolinas.com/Portals/0/Documents/RFPDocuments/23_RFP_Document_7-31-23_corrected_1-8-24.pdf.

[33] Tristate RFP, 2022. https://tristate.coop/2022rfp.

[34] PNM RFP. 2021. https://www.pnm.com/documents/396023/23816266/PNM+2021+Replacement+Generation+RFP+Instructions+to+Bidders-Final.pdf/9dedc8fb-5a06-7d79-70c9-3e3abb544391?t=1614793768977. While the projects selected to replace San Juan Generating Station were delayed, the final project is expected to be online in July 2024, within the initial requirements of the RFP.

Texas applied for approval of two new hydrogen-capable gas power plants expected to come online by mid-2028, in just four years. Notably, Entergy's proposed plants are designed to allow for streamlined retrofits with CCS equipment and the ability to run entirely on hydrogen fuel to enable compliance with the Rules.[35]

37. Natural gas conversion or co-firing is another option for compliance. An example from Gulf Power shows how quickly this can be done. In 2019 Gulf Power approved plans to convert the last remaining coal units at the Crist Coal Plant to natural gas, with a "project timeline show[ing] permitting beginning by May of [2019], construction beginning in early 2020 and the pipeline in service by mid 2020."[36] Gulf Power's parent utility said in a press release that it would make its energy "much more affordable."[37] With this plan including the construction of an entirely new 38-mile pipeline, it demonstrates that conversion including pipeline extension can happen quickly, and in at least some cases, at a significant cost savings when compared to continuing to operate an aged coal facility.

[35] "Finally, the sustainable qualities of the Dispatchable Portfolio - specifically, enabling the future use of CCS technology at Legend and utilizing turbines capable of hydrogen co-firing at both resources - will protect all ETI customers by ensuring these major investments are positioned to provide reliable and economic power over their full useful lives notwithstanding current and future federal environmental regulations, including the recently finalized rule under Section 111 of the federal Clean Air Act that will impose significant carbon emission reductions starting in January 2032." Entergy Texas, Inc., Application of Entergy Texas, Inc., Docket No. 56693, Public Utility Commission of Texas, June 2024, https://interchange.puc.texas.gov/Documents/56693_2_1400290.PDF

[36] NorthEscambia.com, "Gulf Power Considering Conversion Of Plant Crist To Natural Gas, Pipeline Through North Escambia," 2019, https://www.northescambia.com/2019/02/gulf-power-considering-converting-plant-crist-to-natural-gas-pipeline-through-north-escambia

See also: Gulf Power Company. Docket No. 20200242-EI. Staff's Third Data Request Request No. 1. December 18, 2020. https://www.floridapsc.com/pscfiles/library/filings/2020/13638-2020/13638-2020.pdf

[37] https://newsroom.nexteraenergy.com/FPL-ends-coal-fired-power-generation-in-Florida-continuing-its-efforts-to-build-a-cleaner-more-resilient-and-sustainable-energy-future?l=12

Section 4: Reliability won't be threatened by the rule in the next two years, or in the long run. Portfolios of coal with CCS, coal co-firing with gas, new low-utilization gas, solar, wind, and battery storage can meet peak loads and expanding load growth, offsetting the reliability contributions of coal that will retire or retrofit in the 2030s.

38. Near-term decisions to replace generating resources will not threaten grid reliability, as portfolios integrating existing fossil fuel resources, retrofits such as CCS or gas co-firing, new low-utilization gas generation, solar, wind, and energy storage can meet growing demand, provide energy and grid services where and when they are needed most, offsetting the reliability contributions of coal plants that may retrofit or retire in the 2030s.

The Final Rule will not compromise reliability in the near-term.

39. While initial activities toward compliance with the Rule will begin soon, the focus of those activities over the next several years will be planning the best path for compliance with the rule and initiating procurement processes. As a result, changes to the resource mix on the grid that are specifically driven by the Rule will be minimal over the next two years. Most of the near-term changes to the operations of the grid, forthcoming retirements and new resource additions, are driven by decisions that were made before the rule was finalized.

40. While some stakeholders have expressed concerns about reliability, in fact near-term reliability risks have eased somewhat over the past several years. In 2021 and 2022, the North American Electricity Reliability Corporation (NERC) published Summer Reliability Assessments (SRAs) that identified regions at high risk of shortages under normal weather conditions, including

the grid region encompassing California in 2021 and the Midwest Independent System Operator (MISO) in 2022, and widespread reliability risks under above-normal temperatures and electricity demand.[38] NERC's Summer Reliability Assessment for 2024 finds much lower levels of reliability risks overall, and highlights the significant role that new solar, battery, demand response and other resources have contributed to addressing regional reliability needs. For example, NERC states:

- "New resources including 25 GW of nameplate solar capacity have been added to the [bulk power system] since last summer. Resource additions in assessment areas that were identified as at risk in the 2023 SRA have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins." [39]
- MISO: "New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand."[40]
- WECC-California: "New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower

[38] NERC, Summer Reliability Assessment 2022, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf
NERC, Summer Reliability Assessment 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf
[39] NERC, Summer Reliability Assessment, 2024, , p 6https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, p 6
[40] Ibid, p 5

resources available to balance variability in wind and solar output."[41]

41. Electricity markets and utilities have also demonstrated their ability to meet growing demand, without depending on the types of resources that could be impacted by the Rules. For example, while peak electricity demand has grown by over 10 GW in Texas's competitive ERCOT electricity market,[42] the region has added 2.8 GW of gas-fired combustion turbines, 4 GW of battery energy storage, 12.6 GW of onshore wind, and 14.9 GW of solar capacity since 2020, while only adding 0.2 GW of high-capacity factor combined cycle gas plants over the same time period.[43]

42. Electricity utilities and markets have proven that they are up to the task of maintaining system reliability, building resources that are needed to meet growing demand and replace retiring generators. As the rule does not require existing coal plants or high utilization gas plants to meet a CCS-based standard until 2032, the near-term resource mix – and therefore grid reliability outcomes – will not be affected by the rule. Nevertheless, regional grids around the country are mitigating near-term reliability risks, primarily through accelerating deployment of solar, energy storage, demand response, and in some cases peaking gas resources.

"Baseload" fossil fuel power plants are not needed for reliability; portfolios of low-cost wind and solar, storage, low-utilization gas plants, and improved regional coordination can meet the reliability needs of the grid.

43. Retiring fossil fuel power plants do not need to be replaced one-for-one with another "baseload" dispatchable fossil fuel power plant. This notion

[41] Ibid. p. 5
[42] ERCOT, via GridStatus
[43] EIA Form 860m.

mischaracterizes utility resource planning and electricity market best practices and recent trends.

44. Existing coal-fired power plants, as they are operated today, would not be considered "baseload." While the term "baseload" generally refers to plants that run at high capacity factors to meet the minimum daily demand, many coal plants are no longer operated in this way. The average annual coal capacity factor has declined to 42 percent in 2023,[44] while only 7.5 GW of the 192 GW of coal online operated at a capacity factor of more than 80 percent in 2023.[45] 85 GW, roughly 45 percent of the operating coal fleet, operated at a capacity factor less than 40 percent in 2023.[46] Rather than operating as always-on generators, most coal plants are offline for many days or months at a time when cheaper resources are available and are used more sparingly during periods of high demand or when cheaper generation options are not available. Recognizing this change in operational profile, several utilities have opted to move their coal-fired power plants to seasonal operations, keeping plants offline for large portions of the year and operating them infrequently to meet peak electricity demand.[47]

45. It is not necessary to replace a retiring coal-fired power plant or meet growing electricity demand with high-capacity factor gas plants. Modern resource planning for a reliable grid requires evaluating the system's reliability needs and optimizing a portfolio of resources to meet those reliability needs. Each utility or regional electricity market is made up of a

[44] EIA, "Electric Power Monthly", https://www.eia.gov/electricity/monthly/
[45] Analysis based on EIA Form 860m and EIA Form 923.
[46] Analysis based on EIA Form 860m and EIA Form 923.
[47] For example, Arizona Public Service began operating its Four Corners coal power plant seasonally in 2023. Arizona Public Service, "APS announces plans for seasonal operations at Four Corners Power Plant", 2021 https://www.aps.com/en/About/Our-Company/Newsroom/Articles/aps-announces-plans-for-seasonal-operations-at-four-corners-power-plant

portfolio of many assets, including gas, nuclear, hydro, wind, solar and energy storage. Each asset has its own economic profile, operational considerations, and contribution to the system's reliability needs. Resource planning assembles a portfolio of resources that balances reliability, affordability, and other regulatory or policy goals, much like a diversified financial portfolio reduces risk to an investor. If a utility is facing the need for new capacity to replace a retiring asset or meet growing demand, it is often more cost effective and lower risk to meet that need with a combination of resources including low-cost sources of energy that may be variable, like wind or solar, flexible and fast-responding resources like battery energy storage, and resources that are run infrequently at times during the highest needs on the grid.

46. "Baseload" power plants are not necessary for real-time operational reliability of the electricity system. Electricity grids need resources that can continuously balance supply and demand, react to unexpected changes on the grid like power plants or transmission lines suddenly tripping offline, and otherwise provide grid stability. However, there are numerous ways to supply those real-time reliability services, often with better performance than inflexible coal power plants.[48]

47. Numerous utilities and regional grid operators have shown how portfolios of diverse resources can meet grid needs. For example, in the face of increased load growth in its service territory, Georgia Power proposed a portfolio of

[48] These grid services and the ability of new and existing resources to provide them are summarized in Energy Innovation, "Maintaining A Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions", November 2023, https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/

See also Milligan, M. "Sources of Grid Reliability Services," 2018, https://www.sciencedirect.com/science/article/pii/S104061901830215X

combustion turbines, battery energy storage, and solar.[49] As mentioned above, Texas's competitive electricity market has seen peak electricity demand has grown by over 10 GW,[50] while the market has added 2.8 GW of gas-fired combustion turbines, 4 GW of battery energy storage, 12.6 GW of onshore wind, and 14.9 GW of solar capacity since 2020, while only adding 0.2 GW of high-capacity factor combined cycle gas plants over the same time period.[51]

48. Utility planning and regional market activity shows that high-utilization gas plants simply are not necessary to replace retiring coal plants, many of which are currently operated as low-load or intermediate-load resources. Undertaking planning and procurement activities that limit the role of gas generation without CCS to a 40 percent capacity factor by 2032 will not compromise reliability.

Many utilities and electricity market operators plan to meet electricity system reliability needs without high-utilization gas plants or coal plants without CCS or gas co-firing.

49. Utilities around the country are planning generation portfolios that end the use of coal without CCS by 2032 and avoid building new high utilization combined cycle power plants. In many cases, these utilities developed their plans prior to the EPA's proposed rules, and in some cases, before the passage of the Inflation Reduction Act, which significantly improved the economics of new clean energy resources.

[49] GA Power 2023 IRP Update
[50] ERCOT, via GridStatus
[51] EIA Form 860m.

50. Today, several large regions of the country operate with little or no coal-fired generation.[52] In addition, 24 utilities across the U.S. that currently operate coal-fired power plants have resource plans that would end the use of coal, or retrofit existing coal with CCS, by 2032 or sooner. Collectively these utilities provide over 10 percent of U.S. electricity. Taken together, these utilities plan to retire 27 GW of coal-fired generating capacity by 2032 and meet grid needs by 2032 with 56 GW of solar, 22 GW of wind, 15 GW of energy storage, and 18 GW of gas-fired generation capacity, the majority of which is combustion turbines intended to run infrequently.[53] A subset of these utilities are planning to meet future reliability needs with no new high-utilization combined cycle gas plants, as shown in table 1 below.

Table 1: Utilities with plans to end the use of coal without CCS or gas co-firing by 2032, without new high-utilization combined cycle gas

			Capacity Retirements, Conversions, and Additions by 2032							
Name	**Demand (TWh)**	**Coal Date**	**Coal Rets./ Convs.**	**Other Rets.**	**Solar**	**Wind**	**Energy Storage**	**DSM**	**Gas**	**Other**
Florida Power & Light	123.1	2029	-717	-44	18,774	0	2,322	0	255	0
DTE	41.5	2032	-4,336	-70	5,000	1,000	780	51	0	0
Northern States Power Co (Xcel)	39.9	2030	-1,705	-1,064	1,485	4,950	1,210	1,901	2,767	0
Public Service Co of Colorado (Xcel)	28.9	2031	-2,549	0	1,969	3,407	1,170	0	628	19
Entergy Arkansas	22.3	2030	-1,194	-522	3,430	1,500	200	0	447	0
LADWP	20.8	2025	-1,200	-911	2,196	541	515	411	2,111	140
Public Service Co of Oklahoma	18.2	2026	-465	-79	2,100	2,800	0	75	0	0
Indiana Michigan Power	17.2	2028	-2,123	0	1,300	800	315	-3	750	0
NIPSCO	15.6	2028	-1,191	-155	1,965	204	270	0	353	0
AES Indiana	13.0	2025	-1,487	-233	1,843	650	310	372	0	0
Wisconsin Power & Light	11.2	2026	-1,003	0	764	0	0	0	0	0
Great River Energy	10.7	2031	-1,050	0	200	1,171	202	0		0
Mississippi Power	9.3	2028	-502	-474	0	0	0	0	0	0
Public Service Co of NM	9.2	2031	-200	-146	1,405	400	1,474	20	0	0
Total	**381**		**-19,722**	**-3,698**	**42,431**	**17,423**	**8,768**	**2,827**	**7,311**	**159**

[52] California, New York and New England, and several large utilities like Florida Power and Light reliably operate large electricity systems with little or no coal-fired power plants. Taken together these regions constitute 15 percent of U.S. electricity supply.

[53] Based on analysis of data from EQ Research and review of integrated resource plans.

Sources and Notes: Based on EQ Research data, EIA data and review of utility resource plans. Gas includes only low-utilization combustion turbines, uprates of existing combined cycle plants, and new combined cycle plants that will burn hydrogen by 2032 (LADWP). DSM refers to demand side management. Demand expressed in terawatt-hours (TWh).

51. Several of the nation's largest utilities are planning to end use of coal without CCS or gas co-firing by 2032. For example, the largest retail utility in the U.S., Florida Power and Light, plans to retire over 700 MW of coal by the end of 2028, build no new gas power plants beyond small capacity improvements at existing plants, and meet growing electricity demand with 19 GW of solar and over 2 GW of energy storage by the end of 2032.[54] Other utilities planning to retire or convert coal by 2032 and avoid building new high utilization combined cycle gas plants include DTE Electric in Michigan, Xcel Energy in Minnesota and Colorado, Entergy Arkansas, Public Service Company of Oklahoma, Indiana Michigan Power Company, AES Indiana, Great River Energy (a generation and transmission cooperative), and Public Service Company of New Mexico.

52. Regional market operators are also accounting for a significant transition in generation resources. For instance, MISO conducts a scenario development exercise to inform the grid operator's transmission planning and reliability assessment processes. Scenarios developed in this study consistently emphasize a transition away from coal power, minimal new gas, and a significant build-out of solar, wind and energy storage to meet demand.[55]

53. Utility planning emphasizes meeting the reliability needs of the grid, and these utilities are no exception. All the utility resource plans summarized above involve forecasting electricity demand growth, ensuring adequate capacity to meet that demand even under times of stress, and accounting for the reliability contribution of solar, wind and battery energy storage. Many

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[54] FPL, "Ten Year Site Plan: 2024-2033" https://www.fpl.com/content/dam/fplgp/us/en/about/pdf/ten-year-site-plan.pdf

[55] MISO, "MISO Futures Report" November 2023, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

of these plans also stress-test their portfolios against extreme weather conditions to ensure that they can perform well even under exceptional circumstances.[56]

[56] Several examples of reliability analyses performed by these utilities are detailed in Appendix A of Energy Innovation, "Maintaining A Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions", November 2023, https://energyinnovation.org/publication/maintaining-a-reliable-grid-under-epas-proposed-111-rules-restricting-power-plant-emissions/

* * *

We declare under penalty of perjury that the foregoing is true and correct to the best of our knowledge and belief.

Executed on June 10, 2024

Ric O'Connell

Michael O'Boyle

Brendan Pierpont

DECLARATION OF GARY T. ROCHELLE IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

I, Gary T. Rochelle, declare as follows:

Background and experience

1. I am the Carol and Henry Groppe Professor in Chemical Engineering at the University of Texas at Austin, where I have been a faculty member since 1977. In this role, I lead a research program focused on amine scrubbing for CO_2 capture.

2. This declaration is submitted in support of Environmental and Public Health Respondent-Intervenors in their opposition to Petitioners' stay motions with respect to EPA's rule, "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Rule").

3. I have extensive experience in air pollution control technology, including over 20 years specifically focused on carbon capture.

4. I have been closely involved in the development of carbon capture technologies since 2000. Over the past two decades, I have supervised the research of 48 Ph.D. students, with a primary focus on amine scrubbing technologies. This work has resulted in over 250 papers and over 20 patent filings, including patents

for amine-based solvents for CO_2 capture that have been licensed to Honeywell UOP.

5. I have been deeply involved with the development and regulation of flue gas desulfurization (FGD) and other post-combustion pollution control technologies. I worked at the U.S. Environmental Protection Agency from 1971-1973 on flue gas desulfurization. My Ph.D. research (1973–77) examined the synthesis of processes for FGD. From 1977 to 2000 I supervised 34 graduate students developing fundamental understanding and applied concepts of limestone slurry scrubbing and other technologies to manage sulfur dioxide and other pollutants from coal-fired power plants. I consulted for the EPA on sulfur dioxide scrubbing and other emission control technologies from 1973 to 1985.

6. From 1986 to 2000 I supervised 15 graduate students further developing the fundamental and applied understanding of acid gas treating (AGT). AGT uses aqueous amine to remove acid gases such hydrogen sulfide and carbon dioxide from fuel gases including natural gas and hydrogen. This technology was initially applied in 1930 and has been heavily used by the petroleum and petrochemical industry. The mechanisms and design principles of carbon dioxide absorption are well known and applied in many commercial plants.

Post combustion capture (PCC) by amine scrubbing is very similar to flue gas desulfurization (FGD) by limestone slurry scrubbing.

7. PCC is following a development and deployment path like that of FGD. In 1971 EPA promulgated a new source performance standard requiring coal power plants coming on-line after 1977 to limit emissions to less than 1.2 lbs SO_2/MMBTU. Depending on the sulfur content of the coal, this required burning low sulfur coal or removing up to 90% of the sulfur dioxide with the new FGD technology. This standard was based on deployment at a limited commercial scale at two coal boilers. "A lime-slurry scrubbing system, demonstrated for 6 months on two coal-fired units of 125 and 140 MW capacity approached the SO_2 emission limit of 1.2 pounds per million Btu. This operation represents 73 percent removal of SO_2 … where the coal contains 3.0 wt% sulfur." (EPA, APTD-0711, August 1971).

8. It was my observation that flue gas desulfurization was not deployed in the power sector until a regulatory requirement was imposed by EPA, that before the standard was set, it was met with significant resistance. However, once the scrubber-based standard was set, the technology was widely deployed, electric reliability was maintained, and costs of the pollution control came down even further. Flue gas desulfurization by lime/limestone slurry scrubbing quickly became the industry standard.

Early (1966-1973) testing of the lime/limestone slurry scrubbing revealed reliability problems with plugging and scaling by precipitation in the absorber

system. Initial commercial applications to address the new source performance standard used spare absorber modules. Typically a full-scale plant (750 MW) might require only 4 absorbers 30-feet in diameter to treat the full flue gas flow, but it would install 5 absorbers so that one could be taken out of service for cleaning while continuing to treat the full flue gas flow.

9. FGD by lime/limestone slurry scrubbing was poorly developed and understood when it was first deployed. There was little or no fundamental understanding and quantification of the mechanisms of SO_2 absorption, limestone dissolution, and solids precipitation. There was no basis for determining the amount of slurry flow, pH, and excess limestone feed required to achieve 90% SO_2 removal. Ultimately testing in large absorbers was required to determine how to design and build commercial systems that would provide the required performance.

10. In contrast to FGD, amine scrubbing for CO_2 capture is well developed and understood. Ninety years of commercial experience using aqueous amines for acid gas treating and significant fundamental effort such as that in my research program provide highly quantitative models to size the equipment to provide required CO_2 removal and energy performance. There are also many years of operating experience to address practical issues such as process control, corrosion, and emissions.

11. In my role at the University of Texas, I served as principal investigator for a front-end engineering design (FEED) study for carbon capture and sequestration at the Mustang Station of Golden Spread Electric Cooperative, a natural gas-fired power plant in Denver City, Texas.

12. In addition to my academic work, I have been consulting for Honeywell UOP since 2021. Honeywell is performing two FEED studies on large-scale CCS projects.

13. My carbon capture research program is currently sponsored by approximately 17 organizations, including a majority of CCS process vendors. Sponsors also include power producers and international energy companies. Through this work, I advise carbon capture technology vendors on achieving high CO_2 removal rates, minimizing non-CO2 emissions, and overcoming technical challenges with the scale-up and implementation of amine scrubbing.

<u>90% capture is demonstrated and achievable for both coal and gas plants</u>

14. EPA's conclusion that a 90% CO_2 capture rate is technically feasible for power plants is correct based on my experience and the current state of CCS technology. The necessary equipment and materials for achieving this level of capture are commercially available from multiple vendors, and the engineering design principles are well-established.

15. Several large-scale CCS projects on coal-fired power plants, such as Boundary Dam in Canada and Petra Nova in Texas, have demonstrated the technical viability of capturing a significant portion of CO_2 emissions. These capture systems were designed for 90% CO_2 removal and they consistently capture greater than 90% of the CO_2 in the flue gas that they process. These systems were not designed with a requirement or with the redundancy in critical equipment to always capture 90% of the CO_2 from a given gas flow or with the redundancy to always treat all the gas flue or always treat the same amount of flue gas. Therefore, as design and maintenance issues have occurred, they do not always maintain 90% capture of CO_2 as a percentage of the unit's full output.

16. However, with the extensive knowledge from acid gas treating and development of CCS, new plants can be designed to reliably capture 90% of the CO_2 from any specified gas flow. Absorbers can be sized with a larger diameter to address the possibility of greater gas flow from the combustion source. Plants can be reliably designed for CO_2 removal up to 97% by adding packing height to the absorber, a capacity for additional solvent flow, a capacity to use more stripping steam, and more intercooling capacity in the absorber. Such a design would then be able to achieve 90% removal under upset or unexpected adverse conditions.

17. Applying CCS to natural gas combined cycle (NGCC) power plants uses essentially the same amine scrubbing technology as coal plants, with only

minor adjustments needed to accommodate the different flue gas composition. A commercial CCS system was successfully operated on a slipstream at an NGCC plant in Bellingham, Massachusetts. Additionally, FEED studies like the one I led for the Mustang Station in West Texas give me high confidence that amine scrubbing can be effectively scaled up for NGCC applications.

18. Carbon capture technology is flexible and can be engineered to achieve a wide range of CO2 capture rates based on the specific needs and goals of the project. Achieving very high capture rates, even in excess of 97%, is possible, and primarily a matter of design optimization. Higher capture rates can be achieved by incorporating features such as more structured packing to increase contact area between the flue gas and solvent, more intensive CO2 stripping to regenerate the solvent, and intercooling to maintain optimal absorption temperatures.

Capture systems are scalable

19. Carbon capture systems can be designed to treat anywhere from a small slipstream of flue gas or the entire output of a large power plant. There is no difference in technology or chemistry, merely building more or larger towers.

20. While many prior CCS projects have opted to treat only a portion of the output from their associated power plant, this choice has been driven by operational convenience and economics rather than technical limitations. Treating a slipstream makes it easier to ensure continuous operation of the capture system,

as flue gas can be routed from other operating units if one unit experiences downtime. However, this is a minor economic optimization and not a fundamental technical barrier. CCS systems can be designed to ramp up and down in response to changes in flue gas flow rates.

21. One way a capture system can be scaled up by increasing the size of individual process units (e.g., absorbers, strippers, compressors). The Petra Nova project, for example, demonstrated this scalability by using one absorber with about 45-foot diameter to treat a 250 MW-equivalent slipstream, a significant scale-up from previous demonstrations using about 15-foot diameter absorbers on a 25 MW-equivalent slipstream. Petra Nova utilized the same MHI KS-1 capture technology as the 25 MW Plant Barry project but at ten times the scale.

22. Alternatively, capture systems can be scaled up by installing multiple parallel process trains. For example, in the FEED study I conducted for the Mustang Station in West Texas, which has two natural gas turbines, we found it most practical to design an independent process train for each 230 MW turbine train, with a dedicated absorber and stripper sized to handle the flue gas from each unit. With an independent train for each absorber, the system can operate at half capacity if one turbine is down, or if a critical component in one capture system requires maintenance. The trains can also be constructed in sequence, allowing for one train to start up sooner.

EPA's timelines are reasonable in aggregate

23. I have reviewed the CCS project development timeline provided by the EPA in its technical support document on "Greenhouse Gas Mitigation Measures for Steam Generating Units" (April 2024), the timeline for the Petra Nova demonstration in Texas, and the timeline associated with the Mustang Station FEED.

24. EPA's representative timeline provides 12 months for a feasibility study, followed by a 12-month gap, a 12-month period for FEED studies to be completed by June 2027, 7 months for technical/commercial arrangements, and 24 months for detailed engineering and procurement. These stages overlap with actions to obtain permits (24 months), site work/mobilization (6 months), and the start of construction (24 months, including 6 months' overlap with the end of the engineering and procurement phase). The timeline presents 13 months as the representative timeline for startup and testing, six months of which overlaps with the end of construction.

25. I expect most plants, working diligently, would be able to install and begin running carbon capture by 2032. In my opinion, EPA's representative timeline allows for too much time in some places, and too little in others, but the timeline in aggregate should be possible for most plants given a regulatory requirement and tax incentives.

26. I understand that the Rule includes certain flexibilities for existing coal plants on a site-specific basis. The timeline for getting a capture system operational can be subject to uncertainty, depending on the specific site characteristics and the availability of key resources and personnel. While most coal retrofit projects should be able to begin operations with their capture system operational by 2032, there may be circumstances, such as supply chain disruptions or labor shortages, that could impact the schedule for individual projects.

27. Such challenges associated with this rule are not fundamentally different than those associated with other new pollution control standards, but could arise, depending on the amount of simultaneous demand for engineering talent and materials for carbon capture, and I understand that EPA's rule considered these issues and provides flexibilities in case of obstacles outside of the owner's control.

28. I understand that EPA's modeling anticipates 11 GW of CCS deployment irrespective of the rule, with an incremental 8 GW deployed in response to the rule, which would alleviate supply constraint concerns.

Timeline for feasibility and other pre-FEED work

29. EPA describes the feasibility study phase as consisting of "a preliminary technical evaluation to review the available utilities and siting footprint for the capture plant, as well as screening of the available capture

technologies and vendors for the project, with an associated initial economic estimate," which accurately captures the scope of work involved for the pre-FEED stages of a project.

30. EPA's representative timeline allows for two years between the start of feasibility studies and the start of FEED work. This is more time than would be needed for a developer working promptly. All pre-FEED work can typically be completed within one year. In some cases, the pre-FEED process take up to 18 months, often due to the project stakeholders taking time to evaluate whether they want to proceed with the CCS project, which is less likely given a regulatory requirement. Pre-FEED studies can be done more quickly if the project is considering only one vendor.

31. After the pre-FEED work is completed, developers have typically taken some time before proceeding to the FEED phase, as the developer must select a vendor and secure funding. Historically, this transition period has been longer due in part to the application and selection process for Department of Energy (DOE) funding. However, if power plants were obligated to install CCS or were guaranteed cost recovery for the project, one could expect shorter timelines between the pre-FEED phase and the start of FEED studies.

Near-term costs for existing coal

32. For existing coal-fired power plants that are considering retrofitting carbon capture systems to comply with the EPA's proposed rule, the near-term costs will primarily involve the pre-FEED work. Pre-FEED costs typically constitute less than 0.1% of total project costs.

33. To commence operation with a capture system by 2032 for a carbon capture coal retrofit project, expenditures for FEED work would need to commence no earlier than mid-2026, in line with EPA's representative schedule.

Near-term costs for new gas

34. I understand that the EPA's rule requires natural gas-fired stationary combustion turbine electric generating units with a capacity factor of 40% or higher, which commence construction or reconstruction after May 23, 2023, to comply with an emission standard reflecting 90% carbon capture and storage.

35. In anticipation of this rule and other potential future requirements, many in the carbon capture research and development community have been advocating for years for the development of "capture-ready" plants. Designing a new natural gas-fired power plant to be capture-ready involves several considerations, such as ensuring adequate space for the future installation of carbon capture equipment, oversizing the cooling system to accommodate the additional heat load from the CCS process, and planning for the sourcing of steam to power the CO_2 regeneration process.

36. The timeline of expenditures for a gas retrofit project is similar to that outlined for coal retrofit projects.

Prudent developers should have already started pre-FEED CCS work

37. As of 2021, CO_2 which is captured and sequestered is eligible for an $85 per ton of CO_2 tax credit, so long as construction of the system commences by 2032. Because of this recently-increased incentive and the relatively low cost of pre-FEED studies, it is my opinion that prudent operators of existing coal-fired power plants should have already initiated pre-FEED studies to evaluate the feasibility of retrofitting carbon capture on their plants.

38. Moreover, many states and companies have decarbonization regulations and commitments that counsel for investigating CCS feasibility.

39. Developers of new gas plants should have been considering CCS as a potential future requirement and taking steps to make their facilities capture-ready. The 45Q credit, along with the possibility of future federal or state-level regulations, provides a strong incentive for developers to incorporate CCS-related design considerations into their projects from the outset. By doing so, they can reduce the cost and complexity of retrofitting capture systems later, and position themselves to take advantage of the 45Q credit or other incentives as they become available. Failing to consider CCS in the design of new gas plants could result in

missed opportunities and higher costs down the road, as the power sector continues to face pressure to lower its CO_2 emissions.

40. For example, Entergy Texas just filed an application with the public utility commission to build a new 754 MW combined cycle combustion turbine facility in Port Arthur Texas that is designed to be capture ready. Entergy Texas characterizes this design as serving its "commitment to modernizing the way [it] serves its customers."[1]

Conclusion

41. Based on my extensive experience in carbon capture and storage research, I believe that the EPA's proposed rule requiring new coal-fired power plants and new natural gas plants to implement CCS is technically feasible and that the agency's cost estimates and compliance timelines, which include flexibilities, are reasonable and achievable.

[1] Press Release, Entergy "Entergy Texas proposes new power plants to support rapid growth in Southeast Texas," (June 4, 2024) https://www.entergynewsroom.com/news/entergy-texas-proposes-new-power-plants-support-rapid-growth-in-southeast-texas/.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 7th day of June, 2024.

Gary Rochelle

Gary T. Rochelle

DECLARATION OF ANGELA SELIGMAN IN SUPPORT OF ENVIRONMENTAL AND PUBLIC HEALTH RESPONDENT-INTERVENORS

I, Angela Seligman, declare as follows:

1. I submit this declaration in support of Intervenors' opposition to the motions to stay the Environmental Protection Agency's final rule entitled "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39,798 (May 8, 2024) (Rule).

Background and qualifications

2. I am a geologist with professional technical and policy experience and expertise. I currently work as Clean Air Task Force's (CATF) Senior Carbon Capture Policy Manager. I also led state policy work for CATF in the Midwest. Prior to this, I worked for the North Dakota Department of Environmental Quality (NDDEQ). I also studied the potential for carbon sequestration within rock formations in Utah for the Utah Geological Survey and later obtained my Ph.D. in geology from the University of Oregon. I worked for NDDEQ in the Division of Air

Quality for 4.5 years, from August, 2017 to January, 2022. NDDEQ Division of Air Quality is responsible for implementing federal and state air quality standards and implementing the Clean Air Act (CAA). Therefore, NDDEQ is responsible for developing North Dakota's state plan for the Rule. This includes implementing standards for electric generating units and using its expertise in air quality standards to protect public health and the environment.

3. During my tenure at NDDEQ, I worked on several complex rulemakings, and was engaged on budget and staffing matters when the agency was planning to take primacy of 40 CFR 60, Subparts OOOO and OOOOa. For example, I played an active role on the teams that implemented the Regional Haze Rule and the Affordable Clean Energy (ACE) Rule, EPA's previous regulation limiting greenhouse gas emissions from existing coal-fired electric generating units under Clean Air Act section 111(d), while it was still in effect.

4. Also as part of my work at NDDEQ, I was Project Lead for North Dakota's Low-Carbon Future Initiative where I drafted the initial plans for North Dakota to achieve carbon neutrality. In addition, when I was employed as an Environmental Scientist for NDDEQ, I revised

North Dakota's administrative code on air quality. I was also an acting board member of the North Dakota Atmospheric Resource Board, and, most relevantly, monitored industrial facilities to ensure compliance with state and federal regulations.

5. In preparing this Declaration, I have reviewed the Rule requirements, including those for state planning, and I have read the Petitioner declaration from North Dakota official Mr. James L. Semerad.

6. Based on my experience outlined above, I have the personal knowledge and understanding about what steps North Dakota will need to undertake to implement the Rule, including preparation of a state plan.

<u>State plan development cost and staffing requirements</u>

12. As further described below, based on my experience at NDDEQ, existing agency resources will be sufficient for the agency to plan for and implement the rule.

13. In my career with NDDEQ, EPA proposed and finalized numerous environmental standards, including the Regional Haze and ACE rules, where I participated in developing responsive plans. The Rule's requirements are no more complex or difficult to implement than

numerous other federal regulations and standards the state has successfully implemented. Based on my professional experience at NDDEQ, the marginal costs to develop a state plan for this rule are minimal.

14. There are already staff at NDDEQ who have experience in this type of work. A major responsibility of NDDEQ is compliance with Clean Air Act rules, and the state agency has decades of experience implementing complex federal rules, such as Clean Air Act section 110 state implementation plans for ambient air quality standards and implementation of the Regional Haze Rule. The agencies' annual budget and staffing plans take into account costs and staff required by these compliance duties. The state plan required by the Rule falls within these compliance duties, and I would not expect the Rule to necessitate hiring of any additional staff.

15. This Rule's planning process is analogous to the process used in many rules NDDEQ has successfully implemented. NDDEQ estimates it will take at least 4,000 hours of staff time to understand and implement the Rule, but in the initial state implementation stages, much of the

planning work will be undertaken by the regulated entities, not state agencies.

16. The staffing issues in state planning are not particular to the Rule and will not change based on whether there is a stay of the Rule. There are still staff at NDDEQ who worked on both the ACE Rule and the Regional Haze Rule who are sufficiently experienced to implement the Rule. NDDEQ has implemented similarly complex, if not more complex federal regulations under the Clean Air Act, with similar staffing capacity.

Implementation timeline

17. The Rule's 24-month implementation timeline is reasonable. Based on my direct experience planning for and implementing complex environmental rules, I am confident that the complexity of this rule does not significantly differ from other rules which state agencies regularly handle. The general rulemaking process for NDDEQ requires: 1) review of the rule by the agency; 2) notification to affected facilities, which should not be substantially time consuming; 3) the regulated entity's drafting and submittal of a proposed compliance plan, which likely won't

happen until next year; and 4) review of compliance plans and development of a state plan by the agency.

18. Petitioners underestimate the ability of the agency to implement and comply with federal environmental rulemakings. Based on my experience as a North Dakota regulator, I can say with confidence that North Dakota's environmental and energy regulators consistently, effectively, and efficiently administer their duties as part of the cooperative relationship established by the federal Clean Air Act and other environmental statutes.

Initial outlays for state plan development are minimal

19. Based on my experience and review of the Rule, the preparation and planning that NDDEQ will be required to conduct under the rule during the pendency of this litigation will be similar to the planning duties that are often conducted by the agency in accordance with federal Clean Air Act rules. These duties include interacting with source owners, the Public Service Commission, relevant federal and state agencies, non-governmental organizations, and the public to consider options for compliance and to select the appropriate options for North Dakota.

20. The same planning and coordination occurred with the Regional Haze and ACE Rules while I worked at NDDEQ, and there is no reason to think it would not occur in a similar manner when the state implements the Rule.

21. Following review of the Rule, the initial step for implementing a state plan is to solicit input from the regulated community, which is not a resource-intensive endeavor. For North Dakota, it likely involves outreach to the six coal-fired power plants in the state subject to the rule, totaling 10 EGUs, all plants that NDDEQ staff are already familiar with.

22. It is not unusual for the state to develop standards, state plans, and permits based on business and operational decisions made by the regulated community. North Dakota has already done this process for the rules already mentioned above. NDDEQ knows which companies to reach out to and, with currently available resources, can start the process of gathering the necessary information from the companies to begin the planning process. The Rule will not require significant time from NDDEQ staff until they begin developing their plans after hearing back from the companies. The initial lift will be minimal.

<u>Conclusion</u>

23. This rule does not require NDDEQ to immediately expend significant resources to implement it. The initial costs of developing state plans are minimal, and the Rule's timeline of 24 months for submittal allows the agency enough time to submit the plan, just as the NDDEQ has done numerous times in the past with similar and more complex rules.

I, Angela Seligman, declare under penalty of perjury that the foregoing is true and correct.

Executed this 10 day of June, 2024.

DECLARATION OF SUSAN F. TIERNEY, Ph.D.

I, Susan F. Tierney, declare as follows:

I. QUALIFICATIONS

1. I am a Senior Advisor at Analysis Group, a large consulting firm specializing in economics, finance and policy. My work focuses on energy and environmental economics, regulation, and policy (in the electric industry in particular) and I have worked for clients in the public sector, the private sector, non-profit organizations, and others on a variety of issues.
2. I previously served as the Assistant Secretary for Policy at the U.S. Department of Energy ("DOE"), and in Massachusetts I served as Secretary of Environmental Affairs, Commissioner of the Department of Public Utilities, and head of the state's Energy Facilities Siting Council. I have a Master's degree in City and Regional Planning and a Ph.D. in regional planning from Cornell.
3. I chair the Board on Energy and Environmental Systems at the National Academies of Sciences, Engineering and Medicine and have served on numerous National Academies' expert committees focusing on electric system transition issues. I currently chair the External Advisory Council of the National Renewable Energy Laboratory, currently am a member of the New York State Independent System Operator's Environmental Advisory Committee, previously chaired the DOE's Electricity Advisory Committee, and served on the Secretary of Energy Advisory Board. I currently chair the board of Resources for the Future and am vice-chair of the board of World Resources Institute.
4. I have written extensively on topics relevant to transitions underway in the electric industry over the past three decades and in future years,[1] and mechanisms,

[1] *See* Attachment Tierney-1 to this declaration for a list of some of my relevant reports, white papers, and testimony. A detailed curriculum vitae with my experience can be found at: https://www.analysisgroup.com/globalassets/content/experts_and_staff/senior_adivsors/tierney_cv.pdf

institutions and processes for ensuring electric system reliability.[2] I have testified on such issues before Congressional committees and spoken at expert meetings. Of particular relevance to this declaration, I have authored or co-authored reports on anticipated impacts of environmental regulations on power system reliability, and I have been invited to speak on such topics at technical conferences hosted by the Federal Energy Regulatory Commission ("FERC"), the federal agency with statutory responsibility for overseeing electric reliability.[3]

5. I understand that the new air pollution standards[4] published in May 2024 by the Environmental Protection Agency ("EPA") include the following provisions:

- It sets different greenhouse gas ("GHG") emission limitations for various subcategories of existing fossil-fueled steam electric generating units ("EGUs"). The emission guidelines will be phased in on varied schedules depending on the unit type (e.g., existing coal-fired steam generator versus existing gas-fired steam generator) and the unit's expected operations. For example, coal plants that will operate after 2038 will have to meet new standards by 2032; coal plants operating until 2038 will have to meet new less stringent standards by 2030. Coal plants and oil and/or gas steam EGUs that retire by January 1, 2032 will have no emission reduction obligations under the new rule.
- Existing gas-fired combustion-turbine ("CT") EGUs are not covered by the new EPA rule. New gas-fired CTs will be subject to requirements depending

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[2] *See* in particular: Susan Tierney, "Electric System Reliability and EPA's Regulation of GHG Emissions from Power Plants: 2023," November 7, 2023 ("Tierney 2023 Reliability Report"), (which includes Susan Tierney *et al*., "Electric System Reliability and the EPA's Clean Power Plan: Tools and Practices," February 2015 ("Tierney *et al.* Electric Reliability Tools Report")) and attached to this report as Attachment Tierney-2).

[3] *See* in particular: Tierney 2023 Reliability Report (EPA rulemaking Docket ID No. EPA-HQ-OAR-2023-0072-8582).

[4] Although I refer here to the standards as "EPA Rule," I use this term interchangeably to refer to two rules—the rule for new gas-fired combustion turbines and the rule for existing fossil-fueled steam electric generating units. *See* EPA, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024).

upon their level of output (i.e., their capacity factor[5]) when the unit starts operation. New baseload CTs (units operating at a capacity factor over 40%) will then have until January 1, 2032 to meet a more stringent emission standard. New CT units operating at a lower capacity factor have less stringent requirements: "intermediate load" units with capacity factors between 20% and 40% need to meet the emissions associated with highly efficient technology; new CT units with lower output (i.e., below 20%) will need to meet an emission standard consistent with use of lower emitting fuels.

- By July 2026, states must submit to EPA for its review a plan setting forth how the state will establish, implement and enforce the rule for existing sources. The plan may apply EPA's presumptive standards to applicable EGUs in the state or, with a proper demonstration, issue variances to units with fundamentally different circumstances. Alternatively, each state has the option not to submit a plan, in which case the EPA will establish a federal plan for the state's EGUs.

II. SUMMARY OF CONCLUSIONS:

6. ***Electric reliability organizations plan continually for reliability in a changing electric system regardless of the EPA Rule.*** The electric system is not static; it evolves over time, with changes on both the supply and demand sides of the system. Electric service providers and other reliability entities effectively plan for system needs on a continuing basis because changes occur over time all the time. There are changes in generating technologies' performance and costs, the prices of fuels, the configuration of the grid, legal and regulatory policy requirements and opportunities, consumer preferences, and many other factors.

[5] A "capacity factor" is a statistic indicating the percentage of actual power production of a generating unit compared to its maximum potential to produce power (i.e., actual MWh output divided by (its MW size times the 8760 hours of the year)).

These changes can affect the economics of existing and new power plants, and often lead owners of power plants to make decisions about changes in their supply portfolios under business-as-usual circumstances. Prudent planning and decision-making can lead to unit retirement decisions, new power supply contracts, commitments to continue investment in existing plants and new assets, and so forth. The new EPA Rule introduces only incremental changes to the underlying requirement that asset owners prudently examine the going-forward economics of their EGUs and other resources in light of these myriad changes.

7. ***The EPA Rule allows for compliance flexibility and accommodates electric-system reliability needs***. EPA is clearly aware of the changes occurring in the industry, conferred with federal agencies and others with reliability responsibility as part of the EPA rulemaking process, and took such circumstances (including reliability issues) into account in the design of the new power plant rules. The EPA Rule impacts a small portion of the nation's generating capacity (i.e., 84% of current capacity would not be impacted by the rule at all, and the remainder would not face compliance obligations until 2030 at the earliest). The EPA Rule includes numerous provisions available to states to incorporate into their plans to allow for flexibility in unit compliance generally, for different treatment in instances where a unit has specific attributes that warrant such different treatment (i.e., the so-called remaining useful life and other factors or "RULOF" provision), and for an additional year to comply in situations where a plant is needed for reliability or where a plant owner needs it to complete installation of control equipment due to extenuating circumstances beyond the owner's control. The EPA Rule recognizes the Department of Energy's authority to order a generating unit to remain in operation if reliability considerations warrant doing so.

8. ***The EPA Rule will not jeopardize reliability and will certainly not trigger reliability issues in the near term.*** No generating unit need retire in the next few

years as a result of this EPA Rule. Even if states need to identify future retirement schedules for affected EGUs as part of the July 2026 state plan submissions, this does not mean that units will retire before then. No plant need meet emission limits (or retire) before the EPA Rule's compliance deadlines (i.e., 2032 for most affected coal-fired steam EGUs; 2030 for a subset of them). It is misleading to suggest that there will be immediate and irreparable impacts on grid reliability. If the rule remains in place during this litigation, there are many mechanisms that permit significant compliance optionality and the flexibility to change course in the near term.

9. In this declaration, I address electric-system reliability implications of the EPA Rule, and specifically during the first one to two years in which I understand this litigation will be ongoing. In the following sections, I provide some definitions of key technical terms and concepts that I discuss in my declaration and my specific opinions about reliability, organized according to my key summary conclusions (above).

III. Key Electric Reliability-Related Concepts and Terminology

10. In the electric industry, the term "reliability" relates to the operating practices and attributes of a system of generation, transmission, and distribution facilities, including measures to moderate electricity demand flexibly in response to prices and other signals.

11. To clarify important distinctions and nuances often swept into the ways the word "reliability" is used, I note several distinctions that are important in the electric industry.[6]

[6] These descriptions are based on my many decades of experience in the electric industry and its regulation, as well as (among other things) my participation in several National Academies' studies (e.g., National Academies of Sciences, Engineering and Medicine, "Enhancing the Resilience of the Nation's Electricity System," 2017, https://doi.org/10.17226/24836).

- *Bulk power system reliability*: Reliability in this context relates to the ability of the high-voltage grid to maintain operation without the occurrence of an involuntary outage due to insufficient resources. Outages at the bulk power level can result from major weather events and natural disasters that damage EGUs, fuel-delivery infrastructure, and/or transmission lines, and very rarely result from having insufficient supply to meet demand.
- *Distribution system reliability*: This refers to outages, typically resulting from weather, accidents, or equipment failures that affect the local wires and other local infrastructure connecting consumers to the grid. By far, this is where most outages that customers experience occur.

12. The North American Electric Reliability Corporation ("NERC"), which sets mandatory reliability standards for the electric industry under the authority of the FERC, has defined core reliability concepts and terms,[7] including:

- *"Adequacy."* Given the resources installed on a system, adequacy is a system's ability to "supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."
- *"Operating reliability."* "The ability of the bulk power system to withstand sudden disturbances, such as electric short circuits or the unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment."

13. Given that electric system "reliability" focuses on avoiding involuntary outage events, it is misleading to refer to some technologies as being reliable (e.g., existing coal plants) and others as not (e.g., wind plants).

[7] North American Electric Reliability Corporation, Glossary of Terms, Updated May 8, 2024, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

14. Electric systems (e.g., a utility's own electric system, and/or a regional system operated by an independent Regional Transmission Organization ("RTO")) are traditionally planned to ensure there are adequate resources installed on or available to a system to meet the projected hour of peak demand with a reserve margin in case planned and unplanned equipment outages occur on the system.
15. Additionally, at any moment in an electrical control area (where the resources are under the dispatch direction of a single "balancing authority"), supply and demand must constantly be in balance, with some resources ready to ramp operations up or down in the event of changes in demand, an unexpected equipment outage, or other events so that supply equals demand.
16. In a reliable and economic electric system, resources available to the grid operator tend to be operated according to the principle of economic dispatch, meaning that as demand rises and falls over the course of a day, power plants are dispatched so as to minimize the cost of producing power. Wind, hydropower, solar, and nuclear facilities tend to be dispatched whenever available, as they have the lowest marginal cost of power production. Fossil generation, which has fuel costs, is dispatched after that to fully satisfy demand. Shifts in the output of individual plants occur on a nearly continuous basis given changes in demand and in the relative cost of producing power across available resource options.

IV. Electric Reliability Organizations Plan Continually for Reliability in a Changing Electric System Regardless of the EPA Rule

17. Across the U.S., the electric system is already undergoing significant transitions, driven primarily by: relatively attractive prices for efficient power generation produced by natural gas, wind and solar projects; relatively poor economics of many older and less efficient coal-fired power plants; and federal and state policies and consumer preferences supporting the addition and retention of new

and existing renewable and zero-carbon electricity supplies.[8]

18. Recently, electricity demand has started to grow slowly in some regions after two decades of relatively flat demand. Overall annual growth in U.S. electricity sales in the short term is projected to be less than 1% (2022 through 2025), according to the Energy Information Administration ("EIA").[9] EIA projects higher-than average annual average growth in the West/South Central (3.6%), West/North Central (2.4%) and S. Atlantic (2.4%) regions. EIA projects that other regions will have slower growth than the national average.

19. About 240 gigawatts ("GW") of aged and/or uneconomic generating capacity have retired since 2010 (including 130 GW of coal capacity, 87 GW of gas and/or oil capacity, 10 GW of nuclear capacity). During that period, the nation added 433 GW of capacity, with most from gas-fired units (132 GW), wind projects (116 GW), solar projects (98 GW of utility-scale projects plus 47 GW of rooftop solar), batteries (17 GW), and coal-fired capacity (14 GW).[10]

20. In recent years, these developments unrelated to the EPA Rule have substantially changed the profile of the electric system around the country. As of March 2024, owners of 46 GW of existing coal-fired generating capacity have announced plans to retire those units in advance of 2032. Planning for the exit of such capacity from the system has been underway for many years and is not being triggered by the just-finalized EPA Rule.

21. With these changes already underway, the new EPA Rule affects only a small portion of the electric system. Taking into account fossil generating capacity with already-announced retirement dates, the vast majority (84%) of the nation's

[8] Tierney 2023 Reliability Report.

[9] EIA, Short-Term Energy Outlook, Table 7b, May 2024.

[10] EIA 860 Data for the inventory of utility-scale generating capacity as of the end of 2023; EIA 861 Data for behind-the-meter solar capacity is as of end of 2023, all states, photovoltaic under net metering tariffs. The last new coal plant to enter service was in 2014.

generating capacity is not covered by the EPA Rule at all.[11] The remaining generating capacity would need to take action by 2030 (i.e., 6% of all generating capacity) or 2032 (i.e., another 10%) to comply with the new EPA Rule.

22. With or without EPA's rule, entities responsible for maintaining the electric grid need to take action in the near term to address current reliability issues. Indeed, around the country, countless entities—utility companies, some RTOs, reliability organizations like FERC and NERC, state regulators—are already focusing on and addressing near-term power-system operational issues so as to assure reliable operations around the clock. Electricity outages (or near outages) have occurred recently in parts of the grid, most notably in Texas and in the Mid-Atlantic and Southeastern parts of the United States,[12] but those risks have nothing to do with the EPA Rule. Those actual and near-miss outages occurred on the bulk power system during periods of extreme winter weather, affected substantially by problems in fuel delivery to and operations of fossil EGUs. Notably, recent statements from three RTOs about the EPA Rule do not state that it will lead to near-term incremental reliability issues.[13] The February 2024 statement by the

[11] This percentage includes: (a) all non-fossil generating capacity (e.g., nuclear, hydroelectric, geothermal, wind, solar, and distributed generating (e.g., rooftop solar); (b) coal-fired steam generating capacity with an announced retirement date as of January 1, 2032; (c) other fossil steam generating capacity with an announced retirement date before 2030; and (d) existing gas-fired CTs not covered by the current rules. Data source: detailed generating unit-specific data reported to the EIA; Preliminary Monthly Electric Generator (Release Date April 24, 2024).

[12] *See*: FERC, NERC and Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States," November 2021, pp. 1, 2, 16, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; FERC, NERC, and Regional Entity Joint Staff Inquiry, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," pp. 2, 5, 13. September 21, 2023.

[13] Rather, those statements focus on longer-term considerations about replacing the energy and capacity from plants whose availability and output might be affected in the post-2030 compliance periods identified in the EPA Rule. PJM, "PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations," May 8, 2024, https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx; SPP, "SPP Statement on the Recent EPA Greenhouse Gas Emissions Rule," May 20, 2024, https://www.spp.org/documents/71677/spp%20statement%20on%20epa%20final%20ghg%20rule%20202405020.pdf. MISO, "MISO's Response to the Reliability Imperative," Updated February 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf. This

MISO RTO includes a call to action for "the entire industry – utilities, states and MISO" to work together to address the "immediate and serious challenges" that currently exist on the nation's electric system.

23. The electric system is always evolving, and any changes introduced by the EPA Rule (along with any additional resource planning needs to which it contributes) are incremental to those normal system evolutions and planning activities. It is not correct to assert that the system cannot reliably handle an additional loss of fossil EGUs that is alleged to be driven by the EPA Rule, even with increases in demand for electricity.[14] Electric utilities conducting on-going and prudent resource planning are fully aware of the fundamental changes underway on the electric grid and will not be starting from scratch to consider their options for assuring a reliable and economical supply of electricity for their customers.

24. Prudent resource planning and decision-making always focuses on going-forward costs of maintaining and operating existing generation compared to other alternatives. The going-forward operations and lifetime of a generating unit never result from a single factor (such as a new EPA rule). Rather, prudent resource investment and operating life decisions always take into account many factors, including new investment to maintain an existing EGU in good operating condition, its operating costs (e.g., fuel), how such costs compare to the operating costs of other plants, and the operating attributes of generating units (e.g., their start-up times, time to "ramp" the unit's output up and down), or any new

statement says that if the EPA's GHG rule "drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised." But the EPA Rule will not trigger retirements in the near term, so no replacement capacity needs to come forward for many years to come as a result of the EPA Rule.

[14] The Edison Electric Institute, which represents investor-owned utilities providing electricity to over 250 million consumers, submitted comments in other recent EPA rulemaking dockets that electric companies are planning on vehicle fleet electrification and the electric system can accommodate the increased electricity demand. Comments of the Edison Electric Institute on the EPA's Proposed Rule, Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles: Phase Three, June 15, 2023, Docket ID No. EPA-HQ-OAR-2022-0985; FRL-8952-01-OAR, also submitted into the EPA docket on light-duty/medium-duty vehicles, Comment ID EPA-HQ-OAR-2022-0829-0708.

financial incentives (such as those included in new federal statutes). It is just such prudent planning and decision-making (and not the EPA Rule) that led plant owners to retire units that were relatively costly to maintain and operate, to have already announced the future retirement dates of nearly 70 GW of capacity at fossil steam EGUs,[15] and to potentially retire additional capacity in the near term. The EPA is not triggering those decisions in the near term because its compliance deadlines do not occur before 2030 at the earliest.

25. Even without the EPA Rule, prudent resource planning and decision-making by owners will surely lead to additional retirements of aging infrastructure. Calling such retirements "premature" is inapt in light of the fact that by 2030, 80% of the coal-fired generating capacity that does not currently have an announced retirement date will be at least 40 years old (and 50% of such capacity will be over 50 years).[16] Keeping such old power plant capacity in efficient, safe and economical operating conditions requires significant continued investment.

26. Delay in the rule's implementation will not safeguard affordable and reliable electricity. Safeguarding affordable and reliable electricity requires continual planning and action by many entities including the parties bringing these lawsuits – activities that prudent resource managers would undertake in any event. The responsibilities of organizations such as electric utilities, state regulators, and RTOs include ensuring reliable service to their customers. These organizations are part of an expansive and mission-driven set of entities with responsibility for reliability and with a robust tool kit of actions that can be taken to address

[15] This includes over 40 GW of fossil EGU capacity that is effectively exempt from the new EPA by virtue of the already-committed retirement dates: 46 GW of existing coal-fired steam generating capacity with a retirement date prior to 2032; over 14 GW of existing oil and/or natural gas steam generating capacity with a retirement date prior to 2030. An additional 9.6 GW of existing coal-fired capacity has an announced retirement date between 2032 and the end of 2038, thus not requiring emissions reductions consistent with the EPA's more stringent post-2039 emissions standard. Data are from EIA, Preliminary Monthly Electric Generator (Release Date April 24, 2023), https://www.eia.gov/electricity/data/eia860m/.

[16] EIA 860 Data for the inventory of utility-scale generating capacity as of the end of 2023.

assurance of reliability.[17] Decades of experience in the electric industry indicates that they will take combinations of actions that will help ensure the reliable service they seek to safeguard. This has always occurred as changes in the electric system (e.g., growth in demand for power, generating unit problems leading to new patterns of flows on the grid, new environmental requirements) require action to ensure continued uninterrupted supply of power to consumers.[18]

27. As I have written elsewhere,[19] "A common theme in past EPA efforts to control air pollution from existing power plants is concern that the implementation of new rules will harm electric system reliability. Yet past implementation of such power-plant emissions regulations has not led to such outcomes, in large part due to the existence and use of various tools to ensure reliable operations of the system." In every past instance when such reliability concerns were raised by commenters, "the industry predictably stepped up to ensure that reliability was not compromised – mainly because these many tools are available and because power plant owners, reliability organizations, regulators, other public officials, and a wide range of other stakeholders took myriad actions to ensure that the grid as a whole performed its essential public service functions."

28. The resources installed on the electric system across the country will continue to evolve for reasons entirely unrelated to the EPA Rule. As the EPA notes in its rulemaking analyses, there are significant plans to add new utility-scale wind and solar, battery storage, energy efficiency measures, distributed generation (e.g., rooftop solar), transmission investment, distribution investment, and other actions affecting the electric portfolio, in part driven by federal financial incentives in the Inflation Reduction Act ("IRA"), the Infrastructure Investment

[17] *See* Tierney *et al.* Electric Reliability Tools Report (included in Attachment Tierney-2).

[18] Tierney 2023 Reliability Report (Attachment Tierney-2) (EPA Docket ID No. EPA-HQ-OAR-2023-0072-8582).

[19] Tierney 2023 Reliability Report (Attachment Tierney-2) (EPA Docket ID No. EPA-HQ-OAR-2023-0072-8582).

and Jobs Act ("IIJA") and the policies in many states. Multiple databases that track current company plans to add new utility-scale generating capacity, e.g., EIA's inventory of planned generating units,[20] Lawrence Berkeley Laboratory,[21] and S&P Global,[22] indicate a strong list of projects even before the EPA Rule was announced. Additionally, other new and as-yet unidentified projects will be added through various incentives including:[23] the IRA's tax incentive programs administered by the U.S. Treasury Department; the EPA's Greenhouse Gas Reduction Fund;[24] the DOE's Clean Energy Financing Program and its Energy Infrastructure Investment fund;[25] the U.S. Department of Agriculture's Rural Utilities Service;[26] and state policies (e.g., net-metered rooftop solar systems).

29. Projects with capacity factors below 40% will be able to provide valuable reliability services to the grid, including quick-start and ramping periods, balancing services, firm capacity, and supply during emergency operating periods (as allowed by the EPA Rule) without needing to meet the stricter standards applicable to higher-capacity-factor units. Lower capacity factors are consistent with integration of increasing quantities of intermittent resources and battery

[20] EIA, Inventory of Generators – 163 GW of current planned specific utility-scale projects through 2030, a large portion of which is under construction and/or in receipt of regulatory approvals, with: 81.9 GW of solar; 31.4 GW of battery storage; 20.4 GW of onshore wind; 19.3 GW of gas-fired capacity; 5.3 GW of offshore wind; 3.1 GW of other renewable projects; 1.1 GW of nuclear; and other (e.g., petroleum liquids).

[21] "Active" capacity in the nation's interconnection queues as of the end of 2023 lists 2,598 GW of capacity. LBL, Generation, Storage, and Hybrid Capacity in Interconnection Queues, https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

[22] Karin Rives, "US has 133 new gas-fired power plants in the works putting climate goals at risk," May 15, 2024, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-has-133-new-gas-fired-plants-in-the-works-putting-climate-goals-at-risk-81469493

[23] See, for example, the Executive Summary and Figure ES-1 in the recent paper my colleagues and I have written to explain the many financial incentives in the IRA and IIJA that are available to electric utilities to ensure the prudent provision of efficient and reliable electricity supply: Paul Hibbard, Susan Tierney and Daniel Stuart, "Electric Utilities and the IIJA/IRA: Ensuring Maximum Benefits for Consumers from New Federal Funding Opportunities," January 2024, https://www.analysisgroup.com/globalassets/insights/publishing/2024-electric-utilities-and-the-ira-iija.pdf.

[24] https://www.epa.gov/greenhouse-gas-reduction-fund.

[25] https://www.energy.gov/lpo/energy-infrastructure-reinvestment.

[26] https://www.rd.usda.gov/media/file/download/pace-faqs-v6-09012023.pdf.

configurations. It is too early to know the quantity of new gas-fired capacity that will need to meet the stricter standards as of 2032. EPA modeling indicates a small incremental amount of gas-fired capacity that will need to be added many years from now as a result of the rule. Based on my decades of experience, I know that when generating capacity (and transmission additions, for that matter) are needed to satisfy resource adequacy and operational reliability requirements, they can move through permitting and other regulatory approval processes.

V. The EPA Rule Allows for Flexibility and Accommodates/Supports Electric System Reliability

30. While EPA is not responsible for maintaining electric system reliability, the agency did considerable due diligence and consulted repeatedly with industry, other federal agencies, and other entities that are charged with that responsibility.[27] EPA is clearly aware of the changes occurring in the industry and took such circumstances (including reliability issues) into account in its consideration of the record and its design of the new power plant rules.[28] As a result, EPA included many flexibilities and a reliability safety valve in its rule.

31. Specifically, EPA consulted with: the DOE and FERC (including participating in FERC's electric reliability workshop); utilities and other grid operators (e.g., RTOs); experts in grid reliability; and others in the electric industry. EPA entered into a memorandum of understanding with the DOE to coordinate on grid reliability issues.[29] EPA received and reviewed comments on reliability issues submitted by entities in response to EPA's proposed rule, and then reopened the

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[27] *See*, for example: 89 Fed. Reg., 39798 (May 9, 2024) at 39803.

[28] *See*: 89 Fed. Reg., 39798 (May 9, 2024), at 40013 ("EPA believes that reliability of the bulk power system is of paramount importance") and 39800, 39810-39823; EPA, "Power Sector Trends: Technical Support Document," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072.

[29] DOE and EPA, "Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability," March 2023, https://www.epa.gov/system/files/documents/2023-03/DOE-EPA%20Electric%20Reliability%20MOU.pdf.

record to receive and review further comment specifically on reliability topics.[30] EPA has explained in detail how it analyzed reliability issues, the changes in the final rule to ensure flexibility and reliability, and its recognition of the parallel responsibilities of the many reliability institutions and industry tools that exist to address electric system reliability in the future.[31] EPA concluded that its rule would not jeopardize electric system reliability either alone or in combination with EPA's other power plant rules.[32]

32. EPA made several changes in the final rule and included several provisions to allow for flexibility in compliance approaches in part to address reliability concerns that had been expressed by commenters.[33]

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[30] 88 Fed. Reg., 80692 (November 20, 2023).

[31] 89 Fed. Reg., 39798 (May 9, 2024), at 39800, 39810-39823, 40011-40020; EPA, "Resource Adequacy: Technical Support Document," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8916; EPA, "Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR Technical Memo," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8915. Regarding reliability entities, EPA stated: "The electricity sector also has numerous additional tools to maintain resource adequacy and grid reliability that are often not captured in models. Power companies, grid operators, and regulators have well-established, adaptive procedures and policies in place to preserve electric reliability in response to system changes. Grid operators administer adaptive programs, such as capacity markets and resource adequacy programs, designed to require or incentivize medium- and long term investment in the resources that will be needed to meet demand. In many states, regulators oversee long-term integrated resource planning by utilities to ensure that there is a diverse portfolio of generating resources with the qualities and attributes needed to reliably meet electricity demand. The Federal Energy Regulatory Commission, in partnership with the North American Electric Reliability Corporation and regional reliability organizations, establishes and enforces standards that transmission and generation utilities must meet to ensure operational reliability. Over shorter time horizons, grid operators and regulators have rules that require utilities to follow processes designed to protect reliability before making major plant modifications or retirement decisions. These typically include analysis of the potential impacts of retirement on reliability, identification of mitigating options, and, in some cases, temporary contracts to require operation until longer-term mitigation measures can be put in place. And when severe weather or other emergency circumstances occur, short-term, targeted orders can be issued by DOE's Office of Cybersecurity, Energy Security, and Emergency Response for electricity generators to operate to meet demand notwithstanding environmental permit limits or other restrictions when doing so will best meet the emergency need and serve the public interest." EPA Response to Comments, Chapter 14, p. 37.

[32] EPA's analysis concluded that "the impacts of both the 111 EGU Rules alone and combined with other recent EPA actions related to electricity generating units are projected to result in anticipated power grid changes that (1) remain within the confines of key North American Electric Reliability Corporation (NERC) assumptions, (2) are consistent with peer reviewed projections for the power sector, and (3) are consistent with goals, planning efforts and Integrated Resource Plans (IRPs) of industry itself. We project that the 111 EGU Rules, whether alone or combined with other Rules, are unlikely to adversely affect resource adequacy." (Footnotes in the original text are omitted.) EPA, "Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR Technical Memo," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8915.

[33] 89 Fed. Reg., 39798 (May 9, 2024), at 39800, and 39803 ("The EPA believes the adjustments made to the final rules outlined above are sufficient to ensure the rules can be implemented without impairing the ability of grid operators to

- *"RULOF" Variance:* First, as explained by EPA, states have the opportunity to incorporate into state plans a variance for individual existing power plants based on the generating unit's "Remaining Useful Life and Other Factors": "In general, the standards of performance that states establish must be no less stringent than the presumptively approvable standards of performance in the emission guidelines. However, under certain circumstances, EPA's implementing regulations for section 111(d) of the Clean Air Act allow states to provide variances for individual EGUs based on remaining useful life and other factors. The use of RULOF is applied in limited circumstances at particular facilities that the EPA did not consider in the emission guidelines, where those fundamental differences between the circumstances of a particular facility and the information the EPA considered make it unreasonable for the facility to achieve the applicable presumptive standard of performance or meet the compliance schedule in the emission guidelines."[34] Unlike the next two items, a RULOF variance is not limited to

deliver reliable power. The EPA is nonetheless finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operators' ability to ensure reliability. The short-term reliability mechanism is available for both new and existing units and is designed to provide additional flexibility through an alternative compliance strategy during acute system emergencies that threaten reliability. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires a specific and adequate showing of reliability need that is satisfactory to the EPA, is intended for circumstances where there is insufficient time to complete a state plan revision, and it is limited to the amount of time substantiated, which may not exceed 1 year. The EPA intends to consult with FERC for advice on applications of reliability need that exceed 6 months.")

[34] EPA Fact Sheet Carbon Pollution Standard for Fossil Fuel-Fired Power Plants Final Rule State Plans, https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-state-plans-2024.pdf; 89 Fed. Reg. 39798 (May 9, 2024) at 39845, 39890-39891, 39965 ("States invoking RULOF based on an affected EGU's remaining useful life should demonstrate that the annualized costs of applying the degree of emission limitation achievable through application of the BSER [Best System of Emissions Reduction] for a source with a short remaining useful life are fundamentally different from the costs that the EPA found were reasonable. For purposes of determining the annualized costs for an affected EGU with a shorter remaining useful life, the EPA considers the amortization period to begin at the compliance date for the applicable subcategory. States considering the use of RULOF to provide a less stringent standard of performance for a particular EGU must demonstrate that the information relevant to that EGU is fundamentally different from the information the EPA considered.")

one year. Also, a state may adopt RULOF variances after its plan submission, if appropriate, as revisions to its state plan.

- *Compliance Flexibility*: Second, states may include compliance flexibility approaches for medium-term and long-term categories of existing coal units so as to allow for emission trading, average, and "unit-specific mass-based" compliance (e.g., limiting total emissions within a period rather than limiting emissions rates, such as x pounds/MWh of output).
- *Reliability Assurance Mechanism*: Third, states may include in their plans a "Reliability Assurance Mechanism" allowing a one-year postponement of retirement for existing units that have an enforceable retirement date but where a service suspension or retirement would jeopardize reliability.
- *Deadline Extension*: Fourth, states may include in their plans a mechanism that allows for a one-year compliance extension for existing generating units to install control technologies if the operator documents delay that is outside of its control. EPA may also grant a one-year compliance extension for new baseload gas plants on the same basis.
- *Grid Emergency Reliability Mechanism*: Fifth, the EPA Rule has included a mechanism to accommodate units that are needed to operate during short-term grid emergencies.

33. The EPA Rule also explains the DOE's authority, under Section 202(c) of the Federal Power Act, which allows the Secretary of Energy, as EPA describes, to order "the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements…. DOE has historically issued section 202(c) orders

at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls. Congress provided section 202(c) as the primary mechanism to ensure that when generation is needed to meet an emergency, environmental protections will not prevent a source from meeting that need. To date, section 202(c) has worked well…"[35]

34. The new EPA Rule affects only a small portion of the electric system, and at that, sets compliance dates that begin no sooner than 2030. As previously mentioned in paragraph 21, the vast majority (84%) of the nation's generating capacity is not covered by the EPA Rule at all.[36] Only 6% of total generating capacity would need to come into compliance by 2030 and another 10% by 2032. They may continue operating without CO_2 limitations until then.

35. The emission rates in the current EPA Rule are based on applying pollution control equipment to individual EGUs. Compliance is determined on an average annual basis, not on a daily or other short-term period. The EPA Rule does not set an overall limit on fleetwide emissions, nor does it direct operators to comply by dispatching other resources instead of the affected EGUs.

36. Because applying pollution controls to affected EGUs may change their cost of producing power and other performance characteristics, however, grid operators that follow their normal economic-merit-order dispatch protocols may end up changing the order in which those EGUs will be called upon to generate as an incidental effect. As noted above, dispatch changes occur all of the time based on

[35] 89 Fed. Reg. 39,798 (May 9, 2024), at 39,915.

[36] This data are as of March 2024 and take into account fossil generating capacity with already-announced retirement dates, and includes: (a) all non-fossil generating capacity (e.g., nuclear, hydroelectric, geothermal, wind, solar, and distributed generating (e.g., rooftop solar); (b) coal-fired steam generating capacity with an already announced retirement date as of January 1, 2032; (c) other fossil steam generating capacity with an already announced retirement date before 2030; and (d) existing gas-fired CTs not covered by the current rules. Data source: detailed generating unit-specific data reported to EIA, Preliminary Monthly Electric Generator (Release Date April 24, 2024), https://www.eia.gov/electricity/data/eia860m/.

changes in many factors, such as: the availability of fuel (e.g., the availability of a fossil fuel, or the availability of wind or solar output); the price of fuel; the heat rate (or the amount of energy input per unit of power production) of the unit; the addition or subtraction of other generating units; the addition of a new transmission line (or an outage of a transmission line in a storm); or even the change in demand (e.g., over the course of a day or season of the year).

37. The fossil generating units affected by the EPA Rule are not necessarily any more "reliable" than replacement technologies. The term "reliable" is often misused in this regard. Different generating technologies are neither reliable nor unreliable, but rather provide different services to the electric system. Some plants—e.g., wind, solar, batteries, some CT generators—are quick to start up or increase their output up and down; this is not the case for many coal-fired steam units. Some generating units have fuel onsite and others do not (with the latter exposed to fuel delivery risk). Thus, assertions about the inherent "reliability value" of some generating technologies versus inherent "unreliable character" of others are entirely misplaced.

38. Finally, it is simply not the case that every MW of capacity that retires must be replaced with its same potential to produce power (e.g., at maximum output). This is not a hard and fast rule, and actually depends upon a diverse number of factors (e.g., the retiring plant's current or projected capacity factor given its operating costs relative to other resources on a system in the future; the shape of customers' demand during different time periods; the availability of other resources to meet customers' electrical energy requirements). To illustrate, let's assume there is an existing 200 MW fossil steam unit with the theoretical potential to produce 1,750,000 MWh of electricity if it ran at full output 100% of the time in every hour of a year. But if that unit retires after only producing, say, at a typical 15% capacity factor and having had, say, an accredited capacity value

set at 90% of its 200 MW, then its replacement power would be only 262,800 MWh of power (i.e., 15% of 1,750,000 MWh) with some combination of resources to replace its 180 MW capacity value.

VI. The EPA Rule Will Especially Not Impact the Grid in the Near-term

39. Electric system reliability will not be adversely harmed, and certainly not in the next two years, in the absence of a stay. The EPA Rule will not lead to near-term interruptions in the supply of electricity to consumers. The earliest compliance date for EPA's presumptive standards is January 1, 2030 (deadline for certain coal units to meet a standard reflecting 40% natural gas cofiring) or January 1, 2032 (deadline for other coal units to meet a standard reflecting 90% CCS). Even if an operator intends to retire a unit rather than meet those presumptive emission standards, the unit need not retire before those dates. And, as noted above, each state can establish a different standard or longer compliance deadline for a given unit if the state demonstrates the conditions warranting a RULOF variance.

40. Whatever reliability issues exist at present in various parts of the country have not arisen from the rule and must be (and unquestionably are being) addressed by responsible entities whether or not the rule remains in effect during this litigation.

41. No plants will retire in the near term as a result of the EPA Rule. Even if, arguably, a power plant owner needs to identify its unit-retirement plans by July 2026 when its state needs to file its state plan, a "commitment to retire" is not the same thing as an actual retirement. And if the owners of certain EGUs believe their retirement would be "premature," they are unlikely to close their plants in the next few years before the compliance dates.

42. There are many mechanisms that permit greater optionality and flexibility in complying with the rule, even if a power plant commits to certain decisions in the near-term. For example, even if a state plan filed by July 2026 identifies a coal-fired steam unit as intending to operate beyond 2038 and is in the "long-

term" category with a compliance deadline of January 1 2032 (without an extension for a later compliance deadline if warranted by a demonstration by the unit owner), that state could submit to EPA a modification to its plan if the owner decided (after July 2026 and before the compliance date) that the plant would retire because it was uneconomic to operate (e.g., even for reasons unrelated to the rule). Conversely, if a state plan filed by July 2026 identified a coal-fired steam unit as intending to retire before 2032, that state could submit to EPA a modification to the plan if the owner decided (after July 2026 and before the compliance date) to no longer retire the unit.

43. Here is another example reflecting the ability of power plant owners to "reverse" near-term commitments, based on actual circumstances that have occurred in the past when there was a tight market for CTs: if an asset owner determined in the near term that it (a) needed to put down a deposit on a new turbine so that that owner could be ready to install that turbine in a new CT later on in the 2020s but (b) decided subsequently to forego the development of that CT project, the asset owner could resell its position in the CT manufacturer's queue (or even resell the turbine itself) to a third party.

44. Finally, delaying the rule's effectiveness could actually increase uncertainty about whether and what actions need to be taken to address GHG emissions at affected EGUs. Experience has shown repeatedly that regulatory certainty actually hastens the work of affected parties affected by a rule to address issues such as managing compliance schedules in timely and innovative ways in the context of reliability concerns.

I declare that the foregoing is true and correct,

Susan F. Tierney

Executed on June 9, 2024

Attachment Tierney-1

List of Authored or Co-Authored Reports, Testimony and Regulatory Statements Relevant to This Declaration

Attachment Tierney-1

List of Authored or Co-Authored Reports, Testimony and Regulatory Statements Relevant to This Declaration

Bradley, Michael J., Susan Tierney, Christopher Van Atten, Paul Hibbard, Amlan Saha, and Carrie Jenks, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," August 2010, https://www.npcc.org/content/docs/public/program-areas/rapa/government-regulatory-affairs/2010/mjbaandanalysisgroupreliabilityreportaugust2010.pdf;

Bradley, Michael J., Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer 2011 Update," June 2011, https://obamawhitehouse.archives.gov/sites/default/files/omb/assets/oira_2060/2060_06132011-2.pdf;

Bradley, Michael J., Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

Bradley, Michael J., Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

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National Academies of Sciences, Engineering and Medicine, "The Role of Net Metering in the Evolving Electricity System," 2023, https://www.nationalacademies.org/our-work/the-role-of-net-metering-in-the-evolving-electricity-system.

Susan Tierney, "U.S. Coal-Fired Power Generation: Market Fundamentals as of 2023 and Transitions Ahead," August 9, 2023, https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-coal-generation-report.pdf.

Tierney, Susan, Statement Before the F*ederal Energy Regulatory Commission*, Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, Docket No. AD15-4-000, February 19, 2015.

Tierney, Susan, Testimony Before the Senate Budget Committee, Hearing on "Beyond the Breaking Point: The Fiscal Consequences of Climate Change on Infrastructure," July 26, 2023.

Tierney, Susan, "Testimony Before the House Committee on Science, Space and Technology, hearing on "Lessons learned from the Texas blackouts: Research needs for a secure and resilient grid," March 18, 2021, https://www.nationalacademies.org/ocga/testimony-before-congress/lessons-learned-from-the-texas-blackouts-research-needs-for-a-secure-and-resilient-grid.

Tierney, Susan, Testimony Before the Senate Energy and Natural Resources Committee, at hearing on the electric industry in a changing climate, oral and written testimony, March 5, 2019.

Tierney, Susan, Testimony before the House Committee on Energy and Commerce, Subcommittee on Energy, Hearing on "Powering America: Defining Reliability in a Transforming Electricity Industry, October 3, 2017 (testimony dated September 12, 2017, the original date of the hearing)

Tierney, Susan, "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023," November 7, 2023, https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-electric-reliability-and-epa-ghg-regs.pdf.

Tierney, Susan, "Prepared Statement of Susan F. Tierney," FERC Reliability Technical Conference, Docket No. AD23-9-000, November 9, 2023, https://www.ferc.gov/media/susan-tierney-statement.

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Attachment Tierney-2

Susan Tierney,
"Electric System Reliability and EPA's Regulation of GHG Emissions from Power Plants: 2023,"
November 7, 2023

EPA Docket ID No. EPA-HQ-OAR-2023-0072-8582

ANALYSIS GROUP

Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023

Author:
Susan Tierney

November 7, 2023

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This is an independent study prepared by the author at the request of Environmental Defense Fund. The Report, however, reflects the analysis and judgment of the author alone.

About the Author

Sue Tierney is a Senior Advisor at Analysis Group, where she has advised a wide variety of organizations. Previously, she served as the Assistant Secretary for Policy at the U.S. Department of Energy, and in Massachusetts she was Secretary of Environmental Affairs, Commissioner at the Department of Public Utilities, and Executive Director of the Energy Facilities Siting Council. She chairs the Board of Resources for the Future. She is a trustee of the Barr Foundation and the Alfred P. Sloan Foundation, a board member at World Resources Institute, and chairs the National Academies' Board on Environmental and Energy Systems. She has served on several National Academies' committees: The Future of the Electric Grid; Net Metering in the Evolving Electricity System; and Accelerating Decarbonization in the U.S. She chaired the Department of Energy's Electricity Advisory Committee, and now chairs the External Advisory Council of the National Renewable Energy Lab. She received her Ph.D. in regional planning from Cornell University

About Analysis Group

Analysis Group is one of the largest economics consulting firms, with over 1,200 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, strategy, and policy analysis to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and climate practice area is distinguished by its expertise in economics, finance, market modeling and analysis, economic and environmental regulation, analysis and policy, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

Table of Contents

I. Executive Summary

This report is the latest in a long series of papers, comments and testimony that I have written over the past dozen years on the importance of maintaining electric system reliability as part of the development and implementation of federal regulations addressing air pollution from power plants. This report focuses on the Environmental Protection Agency's newest proposal to regulate greenhouse gas emissions from existing and new fossil generating units under Section 111 of the Clean Air Act.

A common theme in prior instances where EPA issued proposals to control power plant emissions is that industry stakeholders raise concerns that the proposal, if adopted by EPA, would jeopardize electric system reliability and thus conflict with the industry's obligation to provide around-the-clock electricity supply to consumers. Such red flags were raised in 2010 and 2011 about EPA's regulations to control mercury emissions, other hazardous air pollutants and the interstate transport of air pollution. Concerns were raised in the 2013-2015 period when EPA proposed regulations to control emissions of greenhouse gases from fossil-fueled power plants.

In each of those contexts, I authored or co-authored reports and provided testimony and commentary that acknowledged the critical importance of electric system reliability and described the various tools available to the industry to ensure the reliable supply of power even as owners of fossil-fueled generating units were required to take steps to reduce their emissions.[1] Some of these tools were written into the design of EPA's proposals themselves, because in each instance, EPA took into consideration the need to keep the lights on even as power plants complied with new regulations. Other tools are standard elements of the reliability tool kits long available to players in the electric industry.

In every instance in the past dozen years, the industry predictably stepped up to ensure that reliability was not compromised – mainly because these many tools are available and because power plant owners, reliability organizations, regulators, other public officials, and a wide range of other stakeholders took myriad actions to ensure that the grid as a whole performed its essential public service functions.

A common theme in past EPA efforts to control air pollution from existing power plants is concern that implementation of new rules will harm electric system reliability.

Yet past implementation of such power-plant emissions regulations has not led to such outcomes, in large part due to the existence and use of various tools to ensure reliable operations of the system.

In fact, in spite of early industry concerns that EPA's 2015 Clean Power Plan would introduce reliability problems if it went into effect (which it never did, after its implementation was stayed by the court and replaced by EPA in 2019), power-sector carbon dioxide emissions dropped to 34 percent below 2005 levels (thus exceeding the Clean

[1] These writings are referenced with citations in the body of this report.

Power Plan's goal of reducing such emissions by 32 percent by 2030).[2] There is no indication that such emission reductions have led to reliability events (although there is clear indication that extreme weather related to climate change has exacerbated them).

Reduction of power-sector carbon-dioxide emissions is the result of many changes in the electric industry over the past decade. The portfolio of generating resources has transitioned, with retirements of significant coal-fired generating capacity, with gas-fired power plants now providing the largest share of electricity supply and with wind and solar energy making up increasing percentages of electricity generation.[3] Electricity demand – in terms of year-long use and peak demand – has begun to grow in most parts of the country. Fundamental market forces, federal and state policies, and consumer preferences are principal drivers of such changes.[4] Extreme weather events, including frigid cold, droughts, heat waves, wildfires, torrential downpours, and flooding events, have disrupted energy infrastructure, including on the electricity grid (and notably among fossil generating units and their sources and transmitters of natural gas supply).[5]

Many stakeholders have commented that in light of these circumstances, the EPA's recent proposal errs in a number of ways, especially by not allowing more time for compliance and more expansive safety valves to provide more flexibility in the event that reliability problems arise.[6]

Many stakeholders have raised concerns that EPA's newest proposal to regulate GHG emissions from new and existing power plants could jeopardize reliability. Commenters call for longer compliance periods, greater flexibility in implementation and use of broader reliability safety valves.

The EPA regulation, however, reflects the agency's careful attention to reliability and includes many elements designed to ensure that the nation can enjoy the benefits of reduced aire pollution and operational reliability.

Although some of the particulars of the current context are different from those in the past, there are many reasons to feel reassured that this new EPA rule will not jeopardize electric system reliability.

[2] Congressional Budget Office, "Emissions of Carbon Dioxide in the Electric Power Sector," December 2022, https://www.cbo.gov/system/files/2022-12/58419-co2-emissions-elec-power.pdf.

[3] National Academies of Sciences, Engineering and Medicine, "The Future of Electric Power in the United States," 2021 (hereafter "NASEM Future of Electric Power"), https://nap.nationalacademies.org/download/25968.

[4] Susan Tierney, "U.S. Coal-Fired Power Generation: Market Fundamentals as of 2023 and Transitions Ahead," August 8, 2023 (Corrected), https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-coal-generation-report.pdf.

[5] Susan Tierney, Testimony before the U.S. Senate Committee on the Budget, Hearing on "Beyond the Breaking Point: The Fiscal Consequences of Climate Change on Infrastructure," July 26, 2023 (hereafter "Tierney Budget Committee Testimony 2023"), https://www.budget.senate.gov/imo/media/doc/Hon.%20Susan%20F.%20Tierney%20-%20Testimony%20-%20Senate%20Budget%20Committee.pdf.

[6] *See* for example the following sets of comments submitted to the Environmental Protection Agency in Docket EPA-HQ-OAR-2023-0072: American Public Power Association, Comments, August 9, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0566; National Rural Electric Cooperative Association, Comments, August 8, 2023, https://www.electric.coop/wp-content/uploads/2023/08/111-NPRM-Comments-NRECA.pdf; Edison Electric Institute, Comments, August 8, 2023, https://www.eei.org//-/media/Project/EEI/Documents/Resources-and-Media/TFB/EEIComments_111Rules_FINAL_080823.pdf; Power Generators Air Coalition, August 8, 2023 (hereafter "PGen Comments"), https://pgen.org/wp-content/uploads/2023/08/PGen-Comments-on-EPAs-Proposed-GHG-Emission-Standards-and-Guidelines-for-Fossil-Fuel-Fired-EGUs-with-attachments.pdf; Electric Power Supply Association, "Comments", August 5, 2023. https://epsa.org/wp-content/uploads/2023/08/EPSAComments_EPA111_August2023.pdf.

First, the electricity reliability institutions, tools and processes in place today are as good as, if not better than, those in place a decade ago. In addition to its important and continually updated reliability assessments of reliability conditions and outlooks, the North American Electric Reliability Council has instituted new assessments[7] and tools to identify reliability risks and opportunities and to recommend approaches to mitigate them.

Second, significant attention is already being paid by federal and state legislators, reliability organizations, and regulators and other public officials to address confounding circumstances – including gas/electric coordination issues, cybersecurity risks, transitions in generation portfolios, need to enhance the resilience of energy infrastructure to extreme weather events, transmission expansion challenges, wholesale market rule considerations, utility forecasting and planning, equity concerns[8] – so as to assure the grid is fit for purpose in the years ahead.

Third, the EPA proposal to curb GHG emissions from new and existing electric generating units itself includes multiple features to accommodate flexibilities in implementation and compliance-related reliability concerns. These elements of the proposal include: the fact that emissions limits apply only to some subcategories of existing generating units; the long lead times for compliance (with varied deadlines for units with different "operating horizons" and capacity factors); and the ability of states to design implementation plans with a degree of allowance trading and banking; and the commitment of the Department of Energy to use its authorities in a circumstance where compliance at a particular unit might trigger a local reliability concern. There is also the agency's existing system emergency exclusion for reliability.[9]

Unquestionably, there are many other reliability risks that have been identified by NERC, FERC and other organizations.

There is significant work underway to address such risks and needs to continue in earnest, regardless of finalization of the EPA regulation and its eventual implementation in the years ahead.

Unquestionably, the important reliability risks that currently affect the electric industry must be addressed and there is significant work underway to do so.[10] Regardless of requirements that developers of new gas-fired power plants and owners of existing fossil fuel power plants comply with new GHG emission reduction requirements, the electric industry must take the steps necessary to ensure reliability given the many other changes already underway and that are affecting the nation's energy transition.

[7] NERC, "2023 ERO Reliability Risk Priorities Report" (RISC Approved 7-24-2023; NERC Board approved 8-17-2023) (hereafter "NERC Reliability Risk Priorities Report 2023"), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf.

[8] NASEM Future of Electric Power; NASEM 2023 Decarbonization Study.

[9] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-TTTT.

[10] NERC Reliability Risk Priorities Report 2023.

II. Background and Introduction

EPA's May 2023 proposal to regulate GHG emissions from existing and new fossil-fueled power plants has prompted thousands of public comments from stakeholders.[11] Among other things, various commenters from the power industry raise concerns about the implications of the proposed rule for electric system reliability, in part due to the potential for premature retirements of existing fossil-fueled electric generating units, operational constraints on some generating units, and difficulties in adding new gas-fired generating units.[12]

Some commenters point to what they view as technical flaws in the EPA's modeling of the industry's response to the proposed regulation, which in their view gives rise to reliability concerns. Other comments relate to market factors and considerations that the commenters view as inconsistent with EPA assumptions.

Comments address a wide variety of issues, only a small portion of which are addressed here in this report. This paper focuses on the following topics:

- Section III contains a high-level overview of the EPA proposal, especially as it intersects with electric-system reliability.
- Section IV provides context for considering the reliability-related comments and industry reactions to EPA's proposed regulations.
- Section V addresses my responses to thematic and technical concerns raised by stakeholders with regard to reliability issues.

[11] As of October 24, 2023, the EPA reports that 8,034 comments have been posted to Docket EPA-HQ-OAR-2023-0072, and that the agency has received a total of 1,293,352 comments on its proposal. https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072.

[12] *See* for example the following sets of comments submitted to the Environmental Protection Agency in Docket EPA-HQ-OAR-2023-0072: American Public Power Association, Comments, August 9, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0566; National Rural Electric Cooperative Association, Comments, August 8, 2023, https://www.electric.coop/wp-content/uploads/2023/08/111-NPRM-Comments-NRECA.pdf: Edison Electric Institute, Comments, August 8, 2023, https://www.eei.org//-/media/Project/EEI/Documents/Resources-and-Media/TFB/EEIComments_111Rules_FINAL_080823.pdf; Comments of the Power Generators Air Coalition on the U.S. EPA New Source Performance Standards for GHG Emissions, Docket No. EPA-HQ-OAR-2023, 0072, August 8, 2023 (hereafter "PGen Comments"), https://pgen.org/wp-content/uploads/2023/08/PGen-Comments-on-EPAs-Proposed-GHG-Emission-Standards-and-Guidelines-for-Fossil-Fuel-Fired-EGUs-with-attachments.pdf; Electric Power Supply Association, "Comments", August 5, 2023. https://epsa.org/wp-content/uploads/2023/08/EPSAComments_EPA111_August2023.pdf.

III. Overview: EPA's Proposed Regulation for GHG Emissions from Fossil Units

On May 23, 2023, the Federal Register published EPA's proposal under Section 111 of the Clean Air Act to establish new source performance standards ("NSPS") for GHG emissions from new fossil-fueled stationary combustion turbine ("CT") electric generating units ("EGUs"), existing coal-fired EGUs, and from large and frequently used existing fossil CTs.[13] (Smaller existing fossil CTs (whether frequently or infrequently used) are not covered by this proposed rule.)

The Federal Register notice (often referred to as the "Preamble") describes the proposal in detail, identifies topics for comment and is accompanied by several other documents including a Regulatory Impact Assessment.[14] EPA's May 2023 proposal anticipates that the agency will publish final emission guidelines in June 2024, with state plans due to the agency 24 months later (e.g., June 2026).[15]

EPA states that it "has designed these proposed standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity" and is "taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements."[16]

More specifically, EPA states that it "has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system."[17]

In addition to its regular interactions with federal agencies involved in matters affecting the electric industry, EPA drafted its proposal after two rounds of broad stakeholder engagement, including a pre-proposal docket that solicited public input prior design of the proposed regulation.[18] EPA's interagency consultations included

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[13] This description of the EPA's proposal draws upon the Preamble published in the Federal Register 33240 Federal Register / Vol. 88, No. 99 at 33240, Tuesday, May 23, 2023, Proposed Rule (for Environmental Protection Agency, 40 CFR Part 60, [EPA–HQ–OAR–2023–0072; FRL–8536–02–OAR], RIN 2060–AV09, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule) (hereafter referred to as the "Preamble"), https://www.govinfo.gov/content/pkg/FR-2023-05-23/pdf/2023-10141.pdf.

[14] See the "browse documents" tab at EPA's website for Docket EPA-HQ-OAR-2023-0072, https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072/document.

[15] Preamble, at 33372.

[16] Preamble, at 33243.

[17] Preamble, at 33246.

[18] Preamble, at 33276-77. "In the first round of outreach, in early 2022, the EPA sought input in a variety of formats and settings from States, Tribal nations, and a broad range of stakeholders on the state of the power sector and how the Agency's regulatory actions affect those trends. This outreach included State energy and environmental regulators; Tribal air regulators; power companies and trade associations representing investor-owned utilities, rural electric cooperatives, and municipal power agencies; environmental justice and community organizations; and labor, environmental, and public health organizations. A second round of outreach took place in August and September 2022, and focused on seeking input specific to this rulemaking. The EPA asked to hear perspectives, priorities, and feedback around five guiding questions, and encouraged public input to the nonregulatory docket (Docket ID No. EPA–HQ–OAR–2022–0723) on these questions as well."

discussions with the Department of Energy ("DOE") that covered reliability and technology issues among other things. Additionally, EPA described its resource adequacy assessment in a Resource Adequacy Technical Support Document.[19]

The proposed rule addresses emissions from certain types of fossil EGUs: new natural gas CT units (including in simple-cycle and combined-cycle configurations); existing fossil steam units (i.e., coal, natural gas, oil); and certain existing gas CTs.[20] The compliance deadlines vary for different types of units depending upon a number of factors relating to size, technology (i.e., steam unit versus combustion turbine) and operating characteristics (e.g., capacity factor, expected time period during which the unit would continue to remain in service), as explained further below.

In setting deadlines, EPA acknowledged that such factors affect the economics of recovering the costs of control technologies[21] and explained that during the early engagement process, "industry stakeholders requested that the EPA '[p]rovide approaches that allow for the retirement of units as opposed to investments in new control technologies, which could prolong the lives of higher-emitting EGUs; this will achieve maximum and durable environmental benefits.' Industry stakeholders also suggested that the EPA recognize that some units may remain operational for a several-year period but will do so at limited capacity (in part to assure reliability), and then voluntarily cease operations entirely."[22]

The proposed rule includes standards for new stationary CT units (which EPA states are likely to be fueled by natural gas) with facilities having different projected levels of output associated with "base load" operations (defined as units with a capacity factor greater than ~50 percent), "intermediate load" operations (units with a capacity factor of 20-~50 percent) and "low load" operations (units with a capacity factor less than 20 percent)).[23]

Between now and 2032, base load and intermediate units would need to meet emissions levels of highly efficient combined cycle ("CC") and CT technology, respectively. Starting in 2032, intermediate units would need to meet emissions associated co-firing with 30-percent low-GHG hydrogen ("H2"). In 2032 and beyond, base-load units would have standards consistent with two options (which EPA calls "pathways"): (a) a "Low-GHG Hydrogen Pathway" with an emissions standard based on co-firing with 30-percent low-GHG H2 starting in 2032, and with

[19] See the EPA "TSD – Resource Adequacy," ID EPA-HQ-OAR-2023-0072-0034 (hereafter referred to as the "Resource Adequacy TSD"), at https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072/document.

[20] "The EPA is not proposing to revise the NSPS for newly constructed or reconstructed fossil fuel-fired steam generating units, which it promulgated in 2015 (80 FR 64510; October 23, 2015). This is because the EPA does not anticipate that any such units will construct or reconstruct and is unaware of plans by any companies to construct or reconstruct a new coal-fired EGU. The EPA is proposing to revise the standards of performance that it promulgated in the same 2015 action for coal-fired steam generators that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to mirror the emissions guidelines, discussed below, for existing coal-fired steam generators. This will ensure that all existing fossil fuel-fired steam generating sources are subject to the emission controls whether they modify or not." Preamble, at 33245.

[21] Preamble, at 33245.

[22] Preamble, at 33245.

[23] EPA, "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions form Fossil Fuel-Fired Electric Generating Units," May 11, 2023, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf; EPA, "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants," Webinar for Communities with Environmental Justice Concerns and Members of Tribal Nations, June 2023, https://www.epa.gov/system/files/documents/2023-06/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

emissions rates consistent with co-firing with 96-percent low-GHG H2 starting in 2038; or (b) a "CCS Pathway" tied to emissions levels of 90 percent carbon capture and storage starting in 2035. These standards are shown in Table 1, along with the timing and character of standards for existing units (explained further below).

Table 1:
EPA Proposed Emissions Guidelines and Standards for Various New and Existing Electric Generating Units

<table>
<tr><th rowspan="3"></th><th colspan="5">New (or Modified) Units</th><th colspan="5">Existing Units</th></tr>
<tr><th colspan="4">New Fossil CTs
(Likely natural gas units)
with compliance starting on in-service date</th><th rowspan="2">New, Recon-structed or Modified steam units (Likely coal)</th><th rowspan="2">Fossil CTs >300 MW and CF>50%* (Likely gas)</th><th colspan="4">Fossil Steam Units**
(coal, gas, oil units) (coal units)</th></tr>
<tr><th>CF <20%</th><th>CF 20-50%</th><th colspan="2">CF >~50%</th><th>If cease operations by 2032</th><th>If cease operations by 2035</th><th>If cease operations by 2040</th><th>If operate beyond 2040</th></tr>
<tr><td>2024</td><td colspan="10">Final rule
(State Implementation Plans due 24 months later)</td></tr>
<tr><td>2025
2026 (SIPs due)
2027
2028
2029</td><td>Use of low-CO_2 fuel</td><td>Use of efficient current CT technology</td><td colspan="2">Use of efficient current CC technology</td><td>2015 standards remain in place***</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2030
2031</td><td></td><td></td><td colspan="2"></td><td></td><td></td><td>Routine O&M (no emissions rate increase)</td><td>Routine O&M, no emissions rate increase, capacity factor <20%</td><td>Co-firing 40% natural gas (with 16% reduction in emissions rate)</td><td>CCS with 90% capture of CO_2</td></tr>
<tr><td>2032
2033
2034</td><td></td><td>Add co-firing with 30% low-GHG H2</td><td>Co-firing with 30% low-GHG H2</td><td>Efficient CC units</td><td></td><td>Same as New Fossil CCs with CF >50% (with two options)</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2035
2036
2037</td><td></td><td></td><td></td><td>CCS with 90% capture</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>2038
2039
2040
2041+</td><td></td><td></td><td>Co-firing with 96% low-GHG H2</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Acronyms:

CC (combined cycle); CCS (carbon capture and storage); CF (capacity factor); GHG (greenhouse gas); CO_2 (carbon dioxide); CT (combustion turbine); H2 (hydrogen); MW (megawatt); O&M (operations and maintenance); SIP (State Implementation Plan)

Notes:

Gray-shaded areas indicate years when such plants will no longer operate due to an enforceable commitment from the unit's owner.

* Existing gas-fired CTs: Smaller (<300MW) with capacity factor below 50% not covered by the current EPA GHG proposal.

** Existing gas or oil-fired boilers: routine O&M with no increase in emissions rate

*** Current standards remain in place until such time as EPA makes a new proposal

https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf;
https://www.epa.gov/system/files/documents/202306/111%20Power%20Plants%20Stakeholder%20Presentation_Webinar%20June%202023.pdf.

Large, frequently used existing fossil combustion turbine units would be required to follow those same emissions guidelines after 2032. For modified and reconstructed fossil steam units (which are likely to be coal-fired generating units), existing emissions standards established in 2015 remain in place.

For existing steam and combustion turbine generating units, EPA's Preamble summarizes the compliance deadlines by subcategory of generating units as follows (with emphasis and formatting adjustments added from the original text so as to focus on treatment of different categories of electric generating units):

> In response to this industry stakeholder input and recognizing that the cost effectiveness of controls depends on the unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, **the EPA believes it is appropriate to establish subcategories of existing steam EGUs that are based on the operating horizon of the units**.
>
> The EPA is proposing that for **[existing steam] units that expect to operate in the long-term** (*i.e.,* those that plan to operate past December 31, 2039), the BSER [Best System of Emissions Reduction] is the use of CCS [carbon capture and storage] with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). As explained in detail in this proposal, CCS with 90 percent capture of CO_2 is adequately demonstrated, cost reasonable, and achieves substantial emissions reductions from these units.
>
> The EPA is proposing to define **coal-fired steam generating units with medium-term operating horizons** as those that (1) Operate after December 31, 2031, (2) have elected to commit to permanently cease operations before January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by including it in the State plan, and (4) do not meet the definition of near-term operating horizon units. **For these medium-term operating horizon units**, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO2/MWh-gross basis)….
>
> For **[existing fossil steam] units with operating horizons that are imminent-term**, *i.e.,* those that (1) Have elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the State plan, the EPA is proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO2/MWh-gross basis). The EPA is proposing the same BSER determination for units in the near-term operating horizon subcategory, *i.e.,* units that (1) Have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both of these conditions federally enforceable by including them in the State plan.….
>
> The EPA is also proposing emission guidelines for **existing natural gas-fired and oil-fired steam generating units**. Recognizing that virtually all of these units have

> limited operation, the EPA is, in general, proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate….[24]

Under Section 111(d) and its application to existing electric generating units, states must submit plans to EPA that provide for the establishment, implementation and enforcement of standards of performance for existing sources, with those state-specific standards being at least as stringent as EPA's final guidelines. States may take into account remaining useful life and other factors when applying standards of performance to individual existing sources. EPA is proposing that states submit their State Implementation Plans ("SIPs") within 24 months after EPA finalizes the new rule.

EPA's Preamble explains the agency's approach to considering the implications of the proposed rule for the ability of the grid to maintain resource adequacy and electric system reliability:[25]

> Finally, the EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system. The EPA has evaluated the reliability implications of the proposal in the *Resource Adequacy Analysis* TSD; conducted dispatch modeling of the proposed NSPS and proposed emission guidelines in a manner that takes into account resource adequacy needs; and consulted with the DOE and the Federal Energy Regulatory Commission (FERC) in the development of these proposals. Moreover, the EPA has included in these proposals the flexibility that power companies and grid operators need to plan for achieving feasible and necessary reductions of GHGs from these sources consistent with the EPA's statutory charge while ensuring grid reliability….[26]

EPA concluded that its proposed emissions standards for existing gas-fired and coal units and new gas-fired units would have "very little incremental impact on resource adequacy" relative to the agency's modeled baseline (without the proposed standards in place). EPA estimated, for example, that "the emission guidelines for existing gas would cover 36.8 GW of natural gas EGUs, which represents 7.7 percent of total natural gas capacity in 2035"

[24] Preamble, at 33245-46.

[25] EPA states in the Resource Adequacy Technical Support Document: "As used here, the term resource adequacy is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while reliability includes the ability to deliver the resources to the loads, such that the overall power grid remains stable. This document is meant to serve as a resource adequacy assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the [Inflation Reduction Act]." Resource Adequacy TSD, page 2.

[26] Preamble, at 33246.

and with "only a fraction of this amount ha[ving] a direct effect on resource adequacy" (i.e., meeting peak demand).[27]

The many provisions within EPA's proposed rule that also together address assurance of electric system resource adequacy and operational reliability include a combination of proposal elements and process attributes that provide many ways to address reliability concerns (i.e., at least a decade and in many cases longer to mitigate concerns). These elements include:

- Periods of governmental and stakeholder engagement prior to the 2023 Federal Register notice of the proposal, with discussions of potential interactions of the proposal and electric system reliability.

- Two-year lead times after EPA finalizes the rule in which states prepare their SIPs and identify potential ways (including through emissions averaging and trading) to provide compliance flexibility for affected generating units.

- Various time frames during which existing coal-fired generating units come into compliance with the emissions standards, depending on their operating horizons and output levels.

  - Coal units that commit to close by 2032 have no operating standards applied to them (except for routine operations and maintenance ("O&M")). This is nearly 10 years after notice of the proposed rule, and 8 years after the expected final rule.
  - Coal units that commit to close by 2034 and have low capacity factors (below 20 percent) have no operating standards applicable to them except for continued routine O&M. This is a decade after the expected year in which EPA finalizes the rule.
  - Coal units with longer anticipated retirement dates beyond 2034 have options for complying with the proposed standards – including through co-firing with natural gas and through eventually adding carbon capture and storage.

- Various options for gas-fired combustion turbines to comply:

  - New low load units (less than 20-percent capacity factor) are subject to standards equivalent to use of lower emitting fuels.
  - In the initial phase of compliance, new intermediate (20 to ~50 percent capacity factor) and baseload units (over ~50 percent capacity factor) are subject to GHG emissions rates tied to the most efficient CT and CC technologies, respectively, that are currently available (something that is likely to be efficient from an investor's point of view in any event).

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[27] Resource Adequacy TSD, page 7. Further, EPA explained: "The total available capacity is needed, at most, for only a fraction of the year [i.e., to meet peak demand]; most facilities can run at significantly less than full utilization throughout the year without any impact on resource adequacy or system reliability. Moreover, even those EGUs [electric generating units] that operate at 50% annual capacity factor or below, and therefore avoid any requirements under the proposed emission guidelines for existing gas, could operate at higher utilization during periods of system need without exceeding a 50% capacity factor on an annual basis. Grid planners and system operators assign high capacity accreditation values to natural gas-fired EGUs that operate at a wide range of capacity factors. Therefore, those EGUs that choose to reduce utilization to at or under 50% would receive full capacity accreditation."

- In later years, new intermediate units are subject to lower GHG emissions standards equivalent to co-firing with low-GHG-emitting hydrogen, while new baseload units are subject to standards equivalent to co-firing low-GHG hydrogen *or* use of carbon capture and storage technology.
- Existing units that are relatively large (over 300 MW) and that operate frequently (over 50-percent capacity factor) meeting similar emissions standards as new baseload units during those same post-2032 time periods.
- Existing gas-fired combustion turbines (operating as stand-alone peaking units or in combined cycle configurations) that are either smaller (which would cover most units[28]) or operate at less than 50 percent capacity factor are not covered by these proposed rules.

[28] According to the Energy Information Administration ("EIA"), most CT generating units that are in operation as of August 2023 and owned by an electric utility or an independent power product are less than 300 MW in size:

- There are approximately 1,750 gas-fired combustion turbine generating units. Only two of these units are above 300 MW in size (nameplate capacity). The total nameplate capacity of all of these units is 143,074 MW (with summer capacity rating of 120,420 MW). The average size is 81 MW (nameplate capacity), or 67 MW summer capacity rating.
- There are an additional 1540 gas-fired combined cycle generating units, of which 181 units are over 300 MW in size (nameplate capacity). The total nameplate capacity of all of these units is 291,340 MW (with summer capacity rating of 263,460 MW). The average size is 189 MW (nameplate capacity), or 171 MW summary capacity rating.

EIA, Preliminary Monthly Electric Generator Inventory, EIA 860M data for August 2023, https://www.eia.gov/electricity/data/eia860m/.

IV. Context: Reliability Concerns Raised in Prior EPA Regulatory Proposals

A predictable complement to an EPA proposal to regulate air pollutants from fossil fueled generating units is a call from various stakeholders to ensure that the new regulation would not jeopardize electric system reliability – something often accompanied by requests to modify and/or delay the proposed regulation.

This has happened on numerous occasions over the past dozen years, I have been involved in assessing reliability concerns in these instances, an experience that – along with my continued participation in a variety of fora involved with electric industry transitions – has given me a perspective on how to think about the concerns currently being raised about EPA's May 2023 proposal to regulate GHG emissions from fossil units.

Here are examples of those prior instances.

- In the early 2010s,[29] EPA published its draft Clean Air Interstate Rule ("CAIR"), which would regulate NO_x and SO_2 emissions in dozens of Eastern states and go into effect at the start of 2012. This rule was eventually replaced by the Cross-State Air Pollution Rule ("CSAPR"), issued by EPA in July 2011 for implementation starting in 2015. During the approximately same period, EPA was developing rules to regulate hazardous air pollutants and mercury emissions from power plants, which also affected emissions from fossil fueled generating units. The latter eventually took the form of the proposed Mercury and Air Toxics Standards (May 2011).[30] EPA proposed new source performance standards for new stationary sources in April 2012.[31]
- At the time, reliability concerns were raised by power plant owners, trade associations, and reliability organizations.
    - o I co-authored three reports[32] aimed at assessing the implications of anticipated EPA air-emission regulations for electric-sector reliability, all of which concluded that the electric industry could comply with these EPA regulations without threatening electric system reliability. As I explained in the third of those reports:

> The first report, published in August 2010, concluded that the electric industry is well-positioned to comply with EPA's proposed air regulations without threatening electric system reliability. The summer 2011 update, published in August,

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[29] https://www.epa.gov/sites/default/files/2016-10/documents/2013_full_report_0.pdf; https://www.epa.gov/Cross-State-Air-Pollution/overview-cross-state-air-pollution-rule-csapr#:~:text=This%20rule%20requires%20certain%20states,soot%20pollution%20in%20downwind%20state.

[30] https://www.epa.gov/mats/epa-proposes-mercury-and-air-toxics-standards-mats-power-plants.

[31] https://www.govinfo.gov/content/pkg/FR-2012-04-13/pdf/2012-7820.pdf.

[32] Michael J. Bradley, Susan Tierney, Christopher Van Atten, Paul Hibbard, Amlan Saha, and Carrie Jenks, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," August 2010, https://www.npcc.org/content/docs/public/program-areas/rapa/government-regulatory-affairs/2010/mjbaandanalysisgroupreliabilityreportaugust2010.pdf; Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Summer 2011 Update," June 2011, https://obamawhitehouse.archives.gov/sites/default/files/omb/assets/oira_2060/2060_06132011-2.pdf; Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

> supplemented the original analysis in light of new information and reaffirmed the prior report's major conclusion that the electric industry can comply with EPA's air pollution rules without threatening electric system reliability. The August report noted that proper planning and implementation can secure important public health benefits, reliable electric service, and efficient market outcomes. Th[e] "Fall 2011 Update" focuse[d] on the many tools that are available for ensuring electric reliability as companies comply with the EPA rules by installing modern pollution control systems, utilizing allowances or retiring portions of the fleet that are uneconomic to retrofit. Federal and state regulators agree that the industry has the tools to maintain electric system reliability even in the face of coal plant retirements. In testimony to Congress, FERC Commissioner John Norris stated "[i]n short, based on the information I have reviewed to date on EPA's regulations, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved.[33]

- I also wrote a "field guide" to the many industry studies assessing the impacts of EPA regulations on power supply and co-authored a peer review of an electric industry analysis of the potential impacts of environmental regulation on the U.S. generation fleet, and concluded that the report was based on "worst-case assumptions which have not materialized..."[34]

- I testified before the U.S. Senate Environment and Public Works Committee at its June 30, 2011 Oversight Hearing on Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), where I explained the reasons for concluding that the electric "industry will respond innovatively and effectively, and with confidence that Americans can get the benefit of clean air and reliable electricity."[35] *Because most of these reasons are still relevant today, I repeat this summary here:*

> The U.S. electric industry has a proven track record of doing what it takes to provide the nation with reliable electricity. Regulated electric utilities, competitive electric companies, grid operators, and regulators have a strong mission orientation, along

[33] Michael J. Bradley, Susan Tierney, Christopher Van Atten, and Amlan Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability: Fall 2011 Update," November 2011, https://grist.org/wp-content/uploads/2011/11/reliabilityupdatenovember202011.pdf.

[34] Susan Tierney May 17, 2011 letter to EPA Administrator Lisa Jackson, with three attachments: (a) S. Tierney and C. Cicchetti, "The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet," May 2011; (b) S. Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," January 18, 2011; and (c) S. Tierney, "EPA Regulations, Power Generation Capacity & Reliability," MIT Center for Energy & Environmental Policy Research Workshop – May 5, 2011," https://policyintegrity.org/documents/Tierney_letter_to_EPA_Administrator_Jackson_5-17-2011_-_with_attachments.pdf.

[35] Susan F. Tierney, "Summary of Testimony Before the U.S. Senate Environment and Public Works Committee Subcommittee on Clean Air and Nuclear Safety, June 30, 2011 Oversight Hearing: Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule," https://www.epw.senate.gov/public/_cache/files/e/f/ef424b3a-c948-496d-9438-30674d9e25b3/01AFD79733D77F24A71FEF9DAFCCB056.tierneytestimonycombined.pdf.

with regulatory requirements, that together ensure that reliable electricity supply is a priority.

By 2011, it is not reasonable to suggest that EPA's CATR and Utility Toxics Rule are a surprise, or that EPA's proposed regulations will require actions that are technically and economically infeasible. These regulations have been in the works for many years. EPA's proposals allow more flexibility in compliance approaches than previously anticipated.

Many factors besides these new regulations have encouraged owners of coal-fired power plants to take steps to reduce their air emissions. Many states have already adopted regulations as strict as those proposed by EPA. Some companies with facilities affected by the CATR and Utility Toxics rules are already under court orders to achieve similar outcomes even without the new regulations. And many companies have already taken steps to install appropriate control equipment: in recent months, chief executive officers of some of the most affected utility companies in different parts of the country have told their investors that they are already or will be ready to meet the new EPA air regulations. These facts occur within a context in which low natural gas prices are putting pressure on many of the oldest, least-efficient and uncontrolled coal plants to retire for economic reasons.

Much attention has been, and will continue to be, paid to the impacts of the regulations on electric system reliability. Many assessments published in the past year have called attention to potential gaps that could arise in the absence of market, utility and regulators' responses. These studies highlight potential plant retirements under different sets of assumptions, with the more reasonable estimates indicating strongly that the impacts are manageable, as long as industry and its regulators respond in a timely fashion.

The industry has various tools to assure that reliability will not be adversely affected. Among the more important tools are: the strong system-planning processes of utility transmission companies and regional transmission organizations (grid operators); the opportunities for companies to obtain power resources through the wholesale power markets that exist in many of the affected parts of the country; the strong least-cost planning processes that exist for utilities in other affected areas; the interest and ability of developers of new power projects to bring new supplies to the market; the fact that state and federal [regulators] have a strong track record of taking the steps necessary to ensure that the companies they supervise are meeting their obligation to provide reliable electric service; the large reservoirs of untapped cost-effective energy efficiency in affected states that can be mined relatively rapidly and can help ease impacts on consumers' electricity bills; and the statutory tools available to EPA, the Federal Energy Regulatory Commission ("FERC"), the U.S. Department of Energy ("DOE"), and the President to take actions to ensure reliable system conditions when all else fails.

Finally, recent market developments provide practical, real-world evidence that the EPA clean air regulations are manageable. Notably, the nation's largest competitive wholesale power market – PJM, serving much of the mid-Atlantic and Midwest regions affected by the EPA regulations – has recently conducted its annual auction to purchase capacity so that it will be available far in advance of need. The PJM auction elicited far more capacity offers from existing and new suppliers than is needed for reliability purposes during the period when EPA's new air rules will go into effect."

- During the mid-2010s, EPA was considering approaches to limit GHG emissions and in June 2014 proposed the Clean Power Plan, regulating carbon pollution from existing electric utility fossil generating units. There were myriad concerns raised about the direct impact of such regulations on potential retirements of fossil generating units (especially coal-fired power plants) and apparent consequential reliability concerns for the nation's electric system.

  The North American Electric Reliability Corporation ("NERC"), which is the nation's federally approved Electric Reliability Organization, had previously prepared assessments of the potential impacts of other future environmental regulations (including a November 2011 report on "Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment)".[36] In November 2014, NERC issued its report on "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review."[37] These NERC reports identified retirements of fossil generating units as a major concern, noting the EPA's proposed Clean Power Plan "aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030" and would lead to a major reduction in total generating capacity. NERC expressed its concern that, among other things, "[d]eveloping suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed CPP."

  During that period, I wrote several papers[38] on reliability considerations related to potential EPA regulation of GHG emissions. Among my observations and conclusions in those reports, I note the following here because they are relevant for consideration of the May 2023 EPA proposal to regulate GHG emissions from fossil generating units:

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[36] This report examined implications of several EPA regulatory activities, including the proposed Coal Combustion Residuals rule, the MATS rule, the Cooling Water Intake Structures rule, and the Cross-State Air Pollution Rule. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA%20Section.pdf.

[37] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

[38] Additionally, I testified before Congress on market and reliability considerations associated with EPA's regulation of GHG emissions from fossil fueled power plants: Testimony of Susan F. Tierney, Ph.D. Before the U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and Power, "Hearing on EPA's Proposed GHG Standards for New Power Plants and H.R. _, Whitfield-Manchin Legislation November 14, 2013," https://docs.house.gov/meetings/IF/IF03/20131114/101482/HHRG-113-IF03-Wstate-TierneyS-20131114.pdf.

- In 2014, I wrote a white paper on EPA regulation of GHG emissions, with a focus on implications for electric system reliability.

  > Historically, the reliability red flag has tended to be raised with regard to concerns that compliance with a new environmental rule would require a large portion of generating capacity to be simultaneously out of service to add control equipment, to retire permanently, or otherwise to become unavailable to produce power. To date, implementation of new environmental rules has not produced reliability problems, in large part because the industry has proven itself capable of responding effectively. A very mission-oriented industry, composed of electric utilities, other grid operators, non-utility energy companies, federal and state regulators, and others, has taken a wide variety of steps to ensure reliability."[39]
  >
  > Other factors also allow for cost-effective emissions reductions at Section 111(d) units in ways that do not adversely affect system reliability. A significant amount of existing generating capacity is underutilized. For example, output at natural-gas fired combined-cycle power plants averaged approximately 50 percent in 2012. There is the potential to reduce overall demand through energy efficiency, thus reducing the need to dispatch plants with relatively high emission rates. There is potential to add additional low or zero-carbon electricity supply (e.g., wind and solar; combined heat and power; nuclear uprates). Actions also can be taken to extend the life of, or increase the output from, well-performing generating units that produce no emissions at the facility (e.g., hydroelectric resources, nuclear plants).[40]

- In 2015, I participated in a FERC Technical Conference on reliability considerations relating to EPA's proposed Clean Power Plan, and then co-authored a report[41] that summarized and responded to a range of themes raised by other commenters at the series of Technical Conferences hosted by FERC in February and March 2015. Our report observed the following:

  > Throughout the FERC CPP Technical Conferences, some participants questioned whether, in light of CPP-driven changes in the resource mix, the grid could continue to perform, especially through high energy demand periods or during unexpected events. These participants generally cited three main factors for these concerns: (1) closure of coal-fired power plants that provide energy, capacity, and

[39] Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability," May 2014, https://www.analysisgroup.com/globalassets/content/insights/publishing/tierney_report_electric_reliability_and_ghg_emissions2.pdf.

[40] Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability," May 2014, https://www.analysisgroup.com/globalassets/content/insights/publishing/tierney_report_electric_reliability_and_ghg_emissions2.pdf.

[41] Susan Tierney, Eric Svenson, and Brian Parsons, "Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences," April 2015, https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2015/04/Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-Plan.pdf.

essential reliability services such as reactive power, inertia, and voltage control; (2) inadequate infrastructure to support increased demand for natural gas for power generation in various parts of the country, and/or inadequate natural gas supplies; and (3) higher reliance on renewable and demand-side resources.

The evidence does not support the argument that the proposed CPP will result in a general and unavoidable decline in reliability. While we do expect significant changes to the overall mix of resources under the CPP, we believe resource planners and markets will have sufficient time and resources to respond to a realistic projection of system redispatch and facility retirements. Both FERC-jurisdictional electricity markets and state-regulated resource planning processes have provided and will continue to provide timely planning, operational, and financial signals for new resources that can help maintain reliability. With clear and transparent signals, market participants can respond in different time frames and investment cycles for different types of resources, including but not limited to new gas resources, end-use energy efficiency measures and demand response, renewables, electric transmission, and natural gas pipeline infrastructure. We note that several market participants filed comments with EPA indicating their readiness to step up with solutions to these challenges.[42]

- In 2015, I co-authored several reports that addressed electric reliability issues related to the EPA's Clean Power Plan. The initial report focused on tools and practices available to electric industry and its regulators to ensure reliable electric service even as the federal government begins to regulate GHG emissions from power plants.[43] The other reports examined more specific reliability considerations in two regions – the PJM region and the MISO region – with significant existing coal-fired and other fossil generating capacity that would be affected by the CPP.[44]

Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability. Such warnings are common whenever there is major change in the industry, and play an important role in focusing the

[42] Susan Tierney, Eric Svenson, and Brian Parsons, "Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences," April 2015, https://blogs.edf.org/climate411/wp-content/blogs.dir/7/files/2015/04/Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-Plan.pdf.

[43] Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: Tools and Practices," February 2015 (hereafter "Tierney et al Electric Reliability Tools and Practices" and attached to this report as Attachment 1) https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/electric_system_reliability_and_epas_clean_power_plan_0215.pdf?m=1529956845.

[44] Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: The Case of PJM," March 16, 2015, https://www.analysisgroup.com/globalassets/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_case_of_pjm2.pdf; and Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and the EPA's Clean Power Plan: The Case of MISO," June 8, 2015, https://www.analysisgroup.com/globalassets/content/insights/publishing/analysis_group_clean_power_plan_miso_reliability.pdf.

> attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.
>
> Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan. In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.
>
> The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed. The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out…..
>
> Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding in parallel. Some of the cautionary comments are just that: calls for timely action…
>
> In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

In the end, there were no reliability problems that arose as a result of EPA's proposed and/or adopted regulation of air emissions from fossil-fueled power plants. This outcome occurred even as other EPA air-pollution rules (e.g., mercury controls, air transport regulations) did go into effect.

In fact, as noted previously, even though the EPA's Clean Power Plan was eventually stayed by federal courts and

repealed and replaced by the EPA in 2019,[45] the CPP goal of reducing CO_2 emissions from power plants by 32 percent by 2030 was reached by 2020, a decade earlier than planned by the CPP.[46] By that point, transitions in the electric industry (including retirements of significant and relatively inefficient fossil generating capacity, a shift from coal-fired generation to gas-fired power production, and the addition of significant new wind and solar capacity) had taken place more quickly than had been anticipated when the CPP was under consideration.[47]

In many ways, today's context for considering reliability issues related to EPA's new proposal to regulate power plant GHG emissions differs in a number of ways, in other regards the reliability issues, including tools and practices for ensuring reliability, are not so different than they were in the past decade, as described in the following sections of this report.

[45] https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan#:~:text=Additional%20Resources-,Rule%20Summary,the%20Affordable%20Clean%20Energy%20rule.

[46] CBO, "Emissions of Carbon Dioxide in the Electric Power Sector," December 2022, https://www.cbo.gov/system/files/2022-12/58419-co2-emissions-elec-power.pdf.

[47] *See*, for example, EIA, "Analysis of the Impacts of the Clean Power Plan," May 22, 2015, https://www.eia.gov/analysis/requests/powerplants/cleanplan/.

V. Concerns Raised About EPA's 2023 Proposal: Thematic and Technical Issues

A. Overview: Changing conditions in the nation's electric industry

EPA's Preamble describes the changing conditions in the U.S. electric industry, with observations that rely on and cite to many scholarly and expert analyses. As summarized in the Preamble, these power sector changes and trends include: "a prolonged period of transition and structural change. Since the generation of electricity from coal-fired power plants peaked nearly two decades ago, the power sector has changed at a rapid pace. Today, natural gas-fired power plants provide the largest share of net generation, coal-fired power plants provide a significantly smaller share than in the recent past, renewable energy provides a steadily increasing share, and as new technologies enter the marketplace, power producers continue to replace aging assets with more efficient and lower cost alternatives."[48] EPA notes that many owners of existing coal-fired power plants have either already retired them in recent years due to their no longer being economic to operate and maintain, or have announced their intention to retire specific generating units in the future.[49]

The electric-sector trends observed by EPA in detail in the Preamble are consistent with those described in detail in recent National Academies' consensus studies of which I was a co-author: *The Future of Electric Power in the U.S.* (2021),[50] *Accelerating Decarbonization in the U.S* (2021, 2023),[51] and the *Role of Net Metering in the Evolving Energy System* (2023).[52] These trends are also the subject of numerous other governmental, expert and stakeholder groups, including ones related to gas/electric coordination issues,[53] cybersecurity risks,[54] transitions in

[48] Preamble, at 33255, and 33256-33266 and 33415-33416 more generally.

[49] EPA stated that: "Industry stakeholders have requested that the EPA structure this rule to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA proposes to accommodate those requests." Preamble, at 33255.

[50] NASEM Future of Electric Power.

[51]; NASEM 2021 Decarbonization Study; NASEM 2023 Decarbonization Study.

[52] National Academies of Sciences, Engineering and Medicine, "The Role of Net Metering in the Evolving Electricity System" (2023) (hereafter "NASEM Net Metering Study"), https://www.nationalacademies.org/our-work/the-role-of-net-metering-in-the-evolving-electricity-system.

[53] FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott; FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[54] NASEM, Future of Electric Power.

generation portfolios,[55] need to enhance the resilience of energy infrastructure,[56] and transmission expansion challenges.[57]

The Preamble and the Technical Support Document also acknowledge the important influences and roles of other actions and developments – like the increasingly apparent impacts of a changing climate, changes in electricity demand and consumer preferences, the enactment of the 2021 Infrastructure Investment and Jobs Act and the 2022 Inflation Reduction Act, other changes in the cost and performance of electricity generation technologies and fossil fuels, trends in states' adoption of policies affecting the power sector's reliance on different resource portfolios and its emissions of GHGs, and increasing numbers of power companies with commitments to reduce GHG emissions.[58]

Perhaps with the exception of the two new federal statutes[59] which in 2021 and 2022 established extraordinary new levels of financial support and bolstered federal authority for various public and private investment in clean energy technology, these electric-industry changes have been underway for much of the past decade. As such, many of the discussions of reliability concerns and strategies described in the prior section of this report are entirely relevant today.

That said, there are heightened concerns in recent years, in part due to some recent reliability events (e.g., Winter Storm Uri in 2021 and Winter Storm Elliott in 2022[60]) that stressed electric and other energy infrastructure and in some cases produced blackouts or near blackouts with fatal consequences.[61] There is substantial attention to bulk power system reliability being paid by numerous entities, including by NERC which is capably exercising its

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[55] NASEM, Future of Electric Power; National Academies of Sciences, Engineering and Medicine, "Accelerating Decarbonization of the U.S. Energy System" (2021) (hereafter "NASEM 2021 Decarbonization Study") and "Accelerating Decarbonization in the United States: Technology, Policy and Societal Dimensions" (2023) (hereafter "NASEM 2023 Decarbonization Study"), https://www.nationalacademies.org/our-work/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal-dimensions.

[56] *See* for example: U.S. Department of Energy ("DOE"), "National Transmission Needs Study," October 2023, https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf; DOE, "Biden-Harris Administration Announces $13 Billion to Modernize and Expand America's Power Grid," November 18, 2022, https://www.energy.gov/articles/biden-harris-administration-announces-13-billion-modernize-and-expand-americas-power-grid.

[57] *See* for example: Joint Federal-State Task Force on Electric Transmission, https://www.ferc.gov/media/e-1-ad21-15-000; DOE, "Biden-Harris Administration Announces $3.5 Billion for Largest Ever Investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs," October 18, 2023, https://www.energy.gov/articles/biden-harris-administration-announces-35-billion-largest-ever-investment-americas-electric.

[58] Preamble, at 33249-33266.

[59] The Inflation Reduction Act has been called the first and largest climate policy law enacted by Congress. *See* for example: Emma Newburger, "The U.S. passed a historic climate deal this year – here's a recap of what's in the bill," CNBC, December 30, 2022, https://www.cnbc.com/2022/12/30/2022-climate-recap-whats-in-the-historic-inflation-reduction-act.html; Josh Bivens, "The Inflation Reduction Act finally gave the U.S. a real climate change policy," August 14, 2023, https://www.epi.org/blog/the-inflation-reduction-act-finally-gave-the-u-s-a-real-climate-change-policy/.

[60] FERC – NERC – Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States," November 2021, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; FERC, NERC, and Regional Entity Joint Staff Inquiry, "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations," September 21, 2023, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[61] Budget Committee 2023. Tierney Budget Committee Testimony 2023; Testimony of Dr. Melissa Lott of the Columbia University Center on Global Energy Policy before the Senate Committee on Energy and Natural Resources, Hearing on Electric Reliability, June 1, 2023, https://www.energypolicy.columbia.edu/wp-content/uploads/2023/05/Lott-SENR-Testimony-with-appendix-v20230530-1.pdf.

essential role of calling attention to issues related to the adequacy, security and resilience of the power system.

For example, the most recent NERC Long-Term Reliability Assessment (December 2022)[62] identifies "government policies, regulations, consumer factors, and economic factors" as helping to shape transitions in the bulk power system. Prolonged, extreme weather events[63] and "continuing resource mix challenges"[64] are also creating new reliability challenges in recent and in upcoming years. In short: "Energy systems and the electricity grid are undergoing unprecedented change" with the need for relevant actors to take steps to ensure reliability. Such steps include "effective regional transmission and integrated resource planning processes," the adoption of policies and market mechanisms to ensure the capability of the system to maintain "essential reliability services,"[65] transmission investment,[66] "managing the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services,"[67] and mitigating "the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure."[68]

[62] NERC, "Long-Term Reliability Assessment," December 2022 (hereafter "NERC Long-Term Reliability Assessment 2022"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

[63] "Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather." NERC Long Term Reliability Assessment 2022.

[64] Several such challenges are called out by NERC, including: "reliable interconnection of inverter-based resources," "accommodating large amounts of distributed energy resources," "managing the pace of generation retirements," "maintaining Essential Reliability Services" (e.g., "capability to support voltage, frequency, and dispatchability," as well as reactive support, stability, and ramping/balancing). NERC Long-Term Reliability Assessment 2022.

[65] NERC states that "[v]arious technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue." NERC Long-Term Reliability Assessment 2022.

[66] "There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the 2021 LTRA projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources." NERC Long-Term Reliability Assessment 2022.

[67] "State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks. • Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators. • Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections." NERC Long-Term Reliability Assessment 2022.

[68] "Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures. Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS [Bulk Power System] during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure" including through promoting coordination of these two systems." NERC Long-Term Reliability Assessment 2022.

More recently, NERC published an update report on priority risks that need to be addressed, with identification of "strategic directions" the industry should take to understand, plan for and mitigate such risks.[69] The report highlights "five significant evolving risk profiles":

> **Energy Policy** at the federal, province, state, provincial and local levels is providing incentives and targets for resource changes and end-use applications of electricity. It is further contributing to the **Grid Transformation**, which includes the shift away from conventional synchronous central-station generators toward a new mix of resources that include natural-gas-fired generation; unprecedented proportions of non-synchronous resources, including renewables and energy storage; demand response; smart- and micro-grids; and other emerging technologies which will be more dependent on communications and advanced coordinated controls that can increase the potential **Security Risks**. Collectively, the new resource mix can be more susceptible to long-term, widespread **Extreme Events,** such as extreme temperatures or sustained loss of wind/solar, that can impact the ability to provide sufficient energy as the fuel supply is less certain. Furthermore, there is an associated increase in **Critical Infrastructure Interdependencies**. For example, for natural-gas-fired generation, there is increased interdependency on delivery of fuel from the natural gas industry that also depends on electricity to support its ability to extract and transport gas.

Although NERC does not specifically call out the risks relating to the design or implementation of EPA regulation of GHG emissions from power plants, the report includes decarbonization policy as part of the "energy policy" drivers of changes in demand and supply of electricity and other aspects of grid transformation. NERC's priority reliability risks report includes numerous recommendations to mitigate risks related to energy policy[70] (which NERC describes as including a wide range of federal, state and local policies relating to electrification of buildings and vehicles, other decarbonization policies, as well as adoption of central-station and decentralized renewable, low- and no-carbon resources, and other supply resources).

The NERC reliability risks report also includes recommendations in five other priority areas, which collectively address the complex planning, operational and other challenges that the industry must address to maintain system

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[69] NERC, "2023 ERO Reliability Risk Priorities Report" (RISC Approved 7-24-2023; NERC Board approved 8-17-2023) (hereafter "NERC Reliability Risk Priorities Report 2023"), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf. ("ERO" refers to Electric Reliability Organization.)

[70] "Increased coordination and collaboration between federal, provincial, and state policy makers, regulators, owners, and operators of the BPS as well as with the critical interdependent sectors is needed. Communication, coordination, and collaboration should be early, consistent, and clear to bridge increasingly complex jurisdictional lines. Education for policymakers and regulators to increase awareness of the reliability implications of policy decisions is a critical need. In addition, education for the industry, as the developers of reliability standards, is needed to better understand the processes and implications of policy decisions. Power system reliability requires many actively engaged, closely coordinated partners. NERC and state commissions share common goals in ensuring a reliable, resilient, safe, affordable electricity system that serves all customers. States, and the utilities they regulate, are responsible for the distribution systems, including DERs [distributed energy resources], and with some utilities responsible for resource acquisition and adequacy. As economic regulators, state commissions review and approve utility investment proposals which have long term impacts on power system reliability. State perspectives are important to NERC's success – translating BPS considerations to state-level needs, experience, and policy objectives. Concurrently, NERC's perspectives are important to the States' success..." NERC Reliability Risk Priorities Report 2023.

reliability. (I have included the full list of NERC recommendations in footnotes here to illustrate the number of actions that NERC recommends be taken in upcoming years, regardless of whether federal regulators put in place new requirements to regulate GHG emissions from fossil fuel power plants.) These other four areas are: grid transformation,[71] physical and cyber security,[72] extreme events,[73] and critical infrastructure interdependencies.[74]

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[71] "Grid transformation will continue to require new and innovative approaches, tools, methods, and strategies to be used in planning and operating the BPS. To address these challenges and opportunities, [NERC] encourages the following actions in order of evaluated criticality to have the most impact and likelihood of mitigating the risk: 1. Develop and include energy sufficiency approaches in planning and operating the grid….NERC and the industry should collaborate to better understand and define energy sufficiency and develop approaches that examine the magnitude, duration, and impact across all hours and many years while also considering limitations and contributions to reliability from all resources (including load resources), neighboring grids, and transmission….2. Ensure sufficient operating flexibility during resource and grid transformation….3. Further consider the impacts and benefits of DER resources, electrification, energy storage, hybrid resources, and other emerging technologies….4. Plan for large and rapid load growth….5. Expand marketing to and development of the workforce of the future….6. Expect and be open to dramatically new grid operation approaches and platforms." NERC Reliability Risk Priorities Report 2023.

[72] "1. NERC should develop guidance for industry on the best practices to mitigate the risks from cloud adoption and the use of AI technologies. 2. NERC should continue to facilitate the development of planning approaches, models, and simulation methods that may reduce the number of critical facilities and thus mitigate the impact relative to the exposure to attack. 3. The ERO should take the lead in encouraging government partners to create a supply chain certification system….4. NERC should develop guidance to define best practices for "Secure by Design" and "Adaptive Security" principles in information technology and operational technology systems development and implementation. 5. The Electricity Information Sharing Analysis Center (E-ISAC) should continue to encourage industry efforts on workforce cyber education… 6. NERC should highlight [and provide training on] key risk areas that arise from the EPRI's EMP [electromagnetic pulse] analysis for timely industry action….7. NERC, while collaborating with industry, should continue to evaluate the need for additional assessments of the risks from attack scenarios (e.g., vulnerabilities related to drone activity, attacks on midstream or interstate natural gas pipelines or other critical infrastructure)….8. E-ISAC should continue to execute its long-term strategy to improve cyber and physical security information-sharing, protection, risk analysis, and increase engagement within the electric sector as well as potential foreign adversaries should continue to be addressed by the E-ISAC, other federal partners, and industry to continue diligently working to mitigate threats. 10. The industry must continue to focus on early detection and response to cyber attacks and adopt controls that can be executed to protect critical systems. 11.….NERC should continue to expand the scope of GridEx [exercises] to include and collaborate with cross-sector industries, such as natural gas, telecom, and water as well as state, local, and tribal authorities….12. [Other efforts relating to cybersecurity risk Information sharing should continue]." NERC Reliability Risk Priorities Report 2023.

[73] "1. Conduct special assessments of extreme event impacts, including capturing lessons learned, create simulation models, and establish protocols and procedures for system recovery and resiliency… 2. Accelerate planning and construction of strategic, resilient transmission. …. For instance, prioritize transmission installation with the explicit objective of reducing resilience risk and ensuring "hardening" for anticipated risks….3. Development of tools for BPS resiliency: DOE is performing analyses to evaluate both static, dynamic, and real-time scenarios that affect BPS reliability and resilience including transmission needs and planning studies, and evaluation of asset performance under extremes. NERC should continue to work with DOE on these efforts to ensure robust tools that can be used industry wide to evaluate potential threats to generation, transmission, and fuel supplies. 4. Regional coordination: States and any other applicable governmental authorities should meet collectively to discuss and understand impacts to ensure they are a part of the resiliency discussion….5. Workforce development: Entities should continue to focus on attracting, developing, and retaining the skilled workforce needed to plan, construct, and operate the transforming [grid]. 6. Industry forums: Forums should share and coordinate information sharing on best practices around resiliency efforts related to design considerations, supply chain deliverability issues, and identification and response to major storm events….7. Drills and emergency response: BPS operators should have formal emergency management programs that include periodic drills and exercises…8. Understanding of geomagnetic disturbance events on BPS." NERC Reliability Risk Priorities Report 2023.

[74] "1. NERC should conduct a study to determine the percent of available generation with on-site or firm fuel capacity in each Regional Entity….NERC and industry partners should continue to conduct meetings and conferences to highlight the importance of cross-sector and energy subsector interdependence and coordination, such as the NERC Reliability Summit, NATF/EPRI resiliency summits, the North American Energy Standards Board Forum, and FERC/DOE technical conferences….NERC, in collaboration with industry and industry partners, should continue to identify and prioritize limiting conditions and/or contingencies that arise from other sectors that affect the BPS. NERC and Reliability Coordinators should continue to conduct special assessments that address natural gas availability and pipeline common mode failures. NERC and industry partners should continue to increase emphasis on cross-sector coordination in industry drills ….NERC should investigate the feasibility of potential infrastructure improvements, such as feeder segmentation required to facilitate more pinpoint control of load during emergencies in order to increase the amount of load available for rotating outages. The EPRI and DOE should continue their work on communication alternatives but also the use of same or similar technologies for critical supervisory control and data acquisition data. New technologies should be explored that could assist in providing unique and hardened back-up telecommunication methods for the most critical data. The ERO Enterprise should continue to communicate to state, provincial,

These recommendations encompass a wide variety of actors in industry and government, and touch on specific areas of needed analysis, information sharing and coordination over time as conditions continue to change.

There are other discussions – e.g., in Texas, at FERC-regulated Regional Transmission Organizations ("RTOs"), and at the North American Energy Reliability Board ("NAESB")[75] – to address problems and concerns relating to preparedness and performance of electric facilities and in gas production and delivery, particularly in extreme weather situations. FERC/NERC's reports, for example, concluded that all types of generating technologies failed to adequately prepare for extreme cold weather or freezing conditions, with gas-fired units experiencing significant incremental unplanned outages, in part due to gas production, supply and delivery issues constituting the second-largest cause of unplanned outages after mechanical issues relating to cold and freezing conditions.[76] FERC/NERC's recommendations reflect the lessons learned from past events, including FERC/NERC's specific recommendations to identify critical facility components and systems that need freeze-protection measures and to prepare and execute plans to address such winterization.[77]

I note that many of these recommendations are similar – and in some cases, identical – to recommendations in reports, forums, and studies with which I have been personally involved and which focused on critical actions needed to address the complex changes already underway in the nation's electric system. For example, the National Academies' Future of Electric Power in the U.S. study identified five "major needs" for the future electric power system, including the following (and also made recommendations related to each one): (1) improving our understanding of how the system is evolving; (2) ensuring that electricity service remains clean and sustainable, and reliable and resilient; (3) improving understanding of how people use electricity and keep electricity affordable and equitable in the face of profound change; (4) facilitating innovation in technology, policy and business models relevant to the power system; and (5) accelerating innovation in technology in the face of shifting global supply chains and the influx of disruptive technologies.[78] The National Academies' Net Metering Study describes the local reliability systems that need greater visibility, operational controls and other mechanisms to be ready for increasing deployment of distributed energy resources with new power flows on the grid.[79]

Many of these broader concerns show up in comments and concerns raised in the context of EPA's proposed regulation of existing and new fossil generating units, even though EPA's proposal did not create these issues.

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and federal regulators of natural gas about the critical interdependence of this fuel source with the other infrastructure sectors. NERC and industry partners should continue to evaluate voice and data communication interdependencies and strategies for ensuring continuous communications during an emergency event, particularly as remote working arrangements grow. NERC should continue to encourage industry to consider the unavailability of other critical infrastructures, such as water, sewer, roads, rails, and communications in their emergency plans." NERC Reliability Risk Priorities Report 2023.

[75] North American Energy Standards Board, "Gas Electric Harmonization Forum Report," July 28, 2023, https://naesb.org/pdf4/geh_final_report_072823.pdf. I served as a co-chair of this Forum and co-authored the Foreword with my two co-chairs, Robert Gee and Pat Wood, III.

[76] See, for example, Section IV of the February 2021 Cold Weather Outages staff report by FERC/NERC/Regional Entities. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[77] See, for example, Section IV of the February 2021 Cold Weather Outages staff report by FERC/NERC/Regional Entities. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[78] NASEM Future of Electric Power Study.

[79] NASEM Net Metering Study, especially chapters 2, 6, and 7.

B. Reliability-related themes in comments on EPA's 2023 proposal

Several themes emerge from comments on reliability implications of EPA's proposed power plant GHG rule. These concerns include: the already-challenging operational conditions in the electric system; challenges relating to the ability of the industry to expand the transmission system; and the role of the proposal in leading to premature fossil unit retirements.

First, regarding challenging operational conditions on the electric system as a result of potential increases in demand and changes in the supply portfolio: Whether or not EPA moves forward with its proposed rule, such conditions are present and will continue to grow as operational changes and challenges, as discussed in the prior section. NERC's recommendations in its 2023 priority reliability risks report detail a broad and deep array of actions that should and can be taken to address these issues (including the impacts of any incremental changes introduced by promulgation of EPA's rule). As noted in NERC's report, these efforts are important to undertake now.

Additionally, the long list of specific recommendations that my colleagues and I previously identified as important tools and practices for assuring reliability in the context of EPA's adoption of prior regulations of GHG emissions from power plants still remain relevant here.[80] That report identified the array of key players with responsibilities that relate directly or indirectly to electric-system reliability – including FERC, other federal agencies, NERC, regional reliability organizations, system operators and balancing authorities, states, vertically integrated utilities, other power plant owners, energy efficiency program operators, and others – and potential actions that they can consider taking in the context of new EPA GHG regulations.

If the EPA's proposed rule is finalized in 2024 as anticipated by EPA, the industry will have nearly a decade to address any incremental reliability issues introduced by the rule and shaped by states' SIPs over the subsequent two years (and where the states can hear input from industry stakeholders about how to introduce greater flexibility into their plans).

Most of the nation's power plant capacity is not covered by these regulations, and includes nuclear facilities,[81] central station and distributed renewable facilities,[82] and existing combustion turbine units that are smaller than 300 MW or that operate infrequently (i.e., less that 50percent capacity factor). Notably, most existing gas-fired combustion turbines (operating as stand-alone peaking units or in combined cycle configurations) are smaller than 300 MW and therefore not covered by the proposal. According to the Energy Information Administration's current inventory of power plants, a significant share of such capacity (and associated generating units) is in this "less than 300 MW in size" category, as shown in Table 2:

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[80] See recommendation Tables 1-6 in Tierney et al. Reliability Tools and Practices (Attachment 1 to this report). https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/electric_system_reliability_and_epas_clean_power_plan_0215.pdf?m=1529956845.

[81] Nuclear generating capacity amounts to 100.5 GW. EIA Monthly Generator Inventory (existing generating units with 1 MW or greater capacity (nameplate)), August 2023 (hereafter "EIA Generator Inventory"), https://www.eia.gov/electricity/data/eia860M/.

[82] Capacity of hydro, wind, solar, and geothermal generating facilities greater than 1 MW amounts to 311 GW. EIA Generator Inventory.

Table 2: Existing Gas-Fired Combustion Turbines (Simple Cycle and Combined Cycle)

Gas-Fired CTs	Total In Operation		Total In Operation And <300 MW in Size		Total In Operation and >300 MW in Size	
	# of units	GW total	# of units	GW total	# of units	GW total
CTs (simple cycle CTs)	1,755	141 GW	1,753	140.3 GW	2	0.7 GW
CCs (combined cycle CTs)	1,540	291 GW	1,359	219.0 GW	181	72.0 GW
**All Gas-Fired CTs	3,295	432 GW	3,112	359.3 GW	183	72.7 GW
Percentage of Currently Operating Gas-Fired CTs affected by EPA proposal			94% not covered	83% not covered	6% covered	17% covered
Source: EIA Monthly Generator Inventory (existing generating units with 1 MW or greater capacity (nameplate)), August 2023, https://www.eia.gov/electricity/data/eia860M/.						

An additional 43.7 GW of existing coal capacity[83] is currently scheduled to retire by 2032 (an amount equivalent to 24 percent of total coal-fired capacity) and needs only to perform routine O&M to comply with the EPA proposal. Also, 4.3 GW of coal-fired capacity has planned retirements in 2032 and 2033, thus similarly complying with EPA's proposal if their capacity factor is below 20 percent. This reflects another 2 percent of currently operating coal-fired steam unit capacity. Given that the EPA Section 111(d) rule is not finalized much less in effect, it is reasonable to assume that market forces and other public policies (and/or utility commitments) have led to such existing retirement announcements.

Note that current estimates of lead times for permitting and constructing new non-renewable capacity are: 24 months for battery storage; 36 months for gas-fired simple cycle CTs; and 48 months for gas-fired combined cycles.[84] Even a doubling of such time frames – such as to account quite conservatively for permitting delays or other extensions of lead times for individual projects – could allow for the economical and timely development of new facilities. Many projects are already in interconnection queues or in development, permitting, financing, and/or construction stages, and may be completed and interconnected in the years leading up to proposed implementation of the more stringent elements of EPA's proposals (e.g., post 2032). Before then, new gas-fired facilities entering service are only held to the use of efficient current CT and CC technologies. Of course, significant quantities of wind and renewable capacity are also in some stage of project development.

Second, regarding challenges in the nation's ability to expand the transmission system to support changes in the electric system: Certainly, the difficulties of adding transmission are well known and being addressed in many

[83] EIA's inventory indicates that 92 existing conventional coal units owned by utilities and independent power products and currently in operations have announced retirements by the end of 2031. EIA Generator Inventory.

[84] Paul Hibbard, Todd Schatzki, Charles Wu and Christopher Llop (Analysis Group) & Matthew Lind, Kiernan McInerney, and Stephanie Villarreal (Burns & McDonnell), "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report," September 9, 2020.

fora.[85] FERC has opened and received comments in a proposed rulemaking on transmission planning, cost allocation and interconnection, with final rules issued on generator interconnections in July 2022.[86]

The Infrastructure Investment and Jobs Act acknowledged such challenges in its provisions that provide expanded federal authorities to facilitate transmission expansion. The Congressional Research Service summarized these transmission-related activities as follows:

> Section 40105 of IIJA revises the process for designation of a National Interest Electric Transmission Corridor (NIETC) by the Department of Energy (DOE). A key revision allows for an NIETC designation that may lead to new interstate transmission lines specifically for intermittent (e.g., renewable) energy to connect to the electric grid. Another key change in the section enhances FERC's "backstop" siting authority for transmission lines in NIETCs. This would allow FERC to supersede traditional state permitting of transmission facilities and issue a permit for the construction and operation of certain interstate facilities under defined circumstances, including when a state has denied an applicant's request to site transmission facilities.
>
> Section 40106 establishes the ''Transmission Facilitation Program,'' under which DOE can facilitate the construction of electric power transmission lines and related facilities. Under this program, DOE may potentially enter a capacity contract (for no more than 40 years or 50 percent of the total capacity) with respect to an eligible transmission project; issue a loan to an eligible entity for an eligible transmission project; or participate with an eligible entity in designing, developing, constructing, operating, maintaining, or owning an eligible transmission project. Thus, under a capacity project, DOE could be closely involved in operational support of eligible transmission-line construction. Such an arrangement could help move a transmission project from proposal to construction, as a transmission project is unlikely to be built without significant customer commitment to its use. Section 40106 also establishes a "Transmission Facilitation Fund" to help finance eligible projects deemed to be in the public interest.

The Department of Energy has established a Grid Deployment office and has already made a number of significant commitments in support of new transmission. Recently announced actions include the agency's

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[85] *See*, for example: NASEM Future of Electric Power study; NASEM Decarbonization study; Institute for Policy Integrity, "Transmission Siting Reforms in the Infrastructure and Jobs Act of 2021," December 2021, https://policyintegrity.org/files/publications/Building_a_New_Grid_Policy_Brief_v3_%281%29.pdf; Institute for Policy Integrity, Memo to DOE Grid Deployment Office on Coordination of Federal Authorizations for Electric Transmission Facilities, October 2, 2023, https://policyintegrity.org/documents/Comments_of_Institute_for_Policy_Integrity.pdf; Liza Reed et al., "How are we going to build all that clean energy infrastructure?", Niskanen Center, August, 2021, https://www.niskanencenter.org/wp-content/uploads/2021/08/CATF_Niskanen_CleanEnergyInfrastructure_Report.pdf; James Hewett, "Advancing U.S. Transmission Deployment: Navigating the Policy Landscape," Breakthrough Energy. August 7, 2023, https://breakthroughenergy.org/news/transmissiondeployment/.

[86] FERC, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," 179 FERC ¶ 61,028, No. RM21-17-000, April 21, 2022, https://www.ferc.gov/media/rm21-17-000; https://www.ferc.gov/electric-transmission/generator-interconnection.

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commitment of $1.3 billion to help fund three major new transmission projects[87] and the publication of the National Transmission Needs Study.[88] Combined with the new authorities provided by Congress to DOE and FERC, and the current efforts of the DOE to use them, it is reasonable to assume that transmission bottlenecks and challenges are being addressed on a timeframe consistent with the compliance milestones anticipated by EPA in its proposed rule. Moreover, EPA's assessment of the impacts of the 2023 proposal are relatively conservative with regard to their assumptions about expansion of the interstate transmission system in support of development of renewable electricity projects.[89]

Notably, also, transmission expansion designed to support reliability outcomes tends to be approved more readily than projects aimed primarily at providing economic savings or to support public policy. To the extent that reliability challenges complicate fossil generating units' compliance strategies (e.g., including retirements, as discussed further below), there are numerous examples of successful siting approvals for such lines.[90]

Third, regarding premature retirements of fossil steam units (especially coal-fired generating units): The trends in retirements of coal-fired generation are driven principally by fundamental market economics.[91] EPA's rule allows for plants to stay in operation until the end of 2034 – a decade from now – if the unit maintains a capacity factor of no more than 20 percent (or for any level of output if a unit is retired by 2032). Already, there are dozens of coal-fired steam units with recent capacity factors below or around that levels.[92] And currently, plant owners have indicated retirement plans of approximately a quarter of total coal-fired steam capacity by those dates. Plants that commit to retire by the end of 2039 (fully 15 years from now) will need to co-fire with natural gas starting in 2030. The EPA has modeled estimated retirements of coal plants, but what will ultimately matter from a reliability point of view is the resource adequacy and other operating conditions on the grid at the time a plant is actually planning on retiring. These timelines are many years away.

To the extent that a unit has not yet announced retirement and operating conditions lead to an owner's decision to retire it (due to an uneconomic financial outlook for the facility) by any of those milestone dates, the unit's owner will need to get permission (from a reliability point of view) to retire the facility to determine whether taking the plant permanently out of service would trigger local or regional reliability issues. Most coal-fired generating capacity is either (a) owned by a vertically integrated utility with the ability to request cost recovery of a unit until alternative resources are in place to allow it to retire without adverse consequences to local reliability, or (b) not owned by a

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[87] DOE, "DOE Launches New Initiative from President Biden's Bipartisan Infrastructure Law to Modernize National Grid," January 12, 2022, https://www.energy.gov/oe/articles/doe-launches-new-initiative-president-bidens-bipartisan-infrastructure-law-modernize; DOE, "Biden-Harris Administration Announces $1.3 Billion to Build Out Nation's Electric Transmission and Releases New Study Identifying Critical Grid Needs," October 30, 2023, https://www.energy.gov/articles/biden-harris-administration-announces-13-billion-build-out-nations-electric-transmission.

[88] DOE, "National Transmission Needs Study," October 2023, https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.

[89] See comments of Clean Air Task Force and Natural Resources Defense Council, EPA Docket No. EPA-HQ-OAR-2023-0072, August 8, 2023, pages 45-51, https://cdn.catf.us/wp-content/uploads/2023/08/09090744/CATF-and-NRDC-Comments-on-Proposed-Rule-EPA-HQ-OAR-2023-0072-1.pdf?_gl=1*1ork94d*_ga*MjEyMzQ4MDA3LjE2OTU4NzY5MzA.*_ga_88025VJ2M0*MTY5ODQzOTUyMy40LjAuMTY5ODQzOTUyNC42MC4wLjA.*_gcl_au*MTIxNTk3MjA0Ni4xNjk1ODc2OTMw.

[90] NASEM, Future of Electric Power.

[91] NASEM Decarbonization: Chapters 6 (The Essential Role of Clean Electricity) and Chapter 12 (The Future of Fossil Fuels).

[92] SPGlobal Regional Power Summary, accessed 11-1-2023.

regulated utility but operates in an RTO region which can put in place reliability-must-run compensation arrangements to cover plant O&M costs to keep it in service until alternatives (including wires and non-wires alternatives) are in place, if needed for reliability.[93]

EPA's Resource Adequacy TSD refers to these and other options as mechanisms that help to ensure reliable system operations, which the agency has taken into account in the development of its proposal and accompanying implementation approach.

> The emission reduction requirements under this rule are based on adequately demonstrated cost-reasonable control measures that form the BSER. Some EGU owners may conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. The Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected.[94]

[93] Tierney et al Electric Reliability Tools and Practices; Paul Hibbard, Pavel Darling and Susan Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011, https://www.cleanskies.org/wp-content/uploads/2011/07/PRGSReportAnalysisGroup2011.pdf.

[94] EPA, Resource Adequacy Technical Support Document, https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0034.

More specifically, the EPA Preamble further describes the reliability options available within the proposed rule and existing in current policy, as excerpted in the text box here:

EPA Preamble
Section XIV.F: Grid Reliability Considerations (excerpts)

Preserving the ability of power companies and grid operators to maintain system reliability has been a paramount consideration in the development of these proposed actions.

Accordingly, these proposed rules include significant design elements that are intended to allow the power sector continued resource and operational flexibility, and to facilitate long-term planning during this dynamic period. Among other things, these elements include subcategories of new natural gas-fired combustion turbines that allow for the stringency of standards of performance to vary by capacity factor; subcategories for existing steam EGUs that are based on operating horizons and fuel reflecting the request of industry stakeholders; compliance deadlines for both new and existing EGUs that provide ample lead time to plan; and proposed State plan flexibilities.

In addition, this preamble discusses EPA's intention to exercise its enforcement discretion where needed to address any potential instances in which individual EGUs may need to temporarily operate for reliability reasons, and to set forth clear and transparent expectations for administrative compliance orders to ensure that compliance with these proposed rules can be achieved without impairing the ability of power companies and grid operators to maintain reliability. As such, these proposed rules provide the flexibility needed to avoid reliability concerns while still securing the pollution reductions consistent with section 111 of the CAA.

The EPA routinely consults with the DOE and FERC on electric reliability and intends to continue to do so as it develops and implements a final rule. This ongoing engagement will be strengthened with routine and comprehensive communication between the agencies under the DOE–EPA *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* signed on March 8, 2023.716 The memorandum will provide greater interagency engagement on electric reliability issues at a time of significant dynamism in the power sector, allowing the EPA and the DOE to use their considerable expertise in various aspects of grid reliability to support the ability of Federal and State regulators, grid operators, regional reliability entities, and power companies to continue to deliver a high standard of reliable electric service….

In addition, the EPA observes that power companies, grid operators, and State public utility commissions have well-established procedures in place to preserve electric reliability in response to changes in the generating portfolio, and expects that those procedures will continue to be effective in addressing compliance decisions that power companies may make over the extended time period for implementation of these proposed rules. In response to any regulatory requirement, affected sources will have to take some type of action to reduce emissions, which will generally have costs.

Some EGU owners may conclude that, all else being equal, retiring a particular EGU is likely to be the more economic option from the perspective of the unit's customers and/or owners because there are better opportunities for using the capital than investing it in new emissions controls at the unit. Such a retirement decision will require the unit's owner to follow the processes put in place by the relevant RTO, balancing authority, or State regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place.

In some rare instances where the reliability of the system is jeopardized due to extreme weather events or other unforeseen emergencies, authorities can request a temporary reprieve from environmental requirements and constraints (through DOE) in order to meet electric demand and maintain reliability. These proposed actions do not interfere with these already available provisions, but rather provides a long-term pathway for sources to develop and implement a proper plan to reduce emissions while maintaining adequate supplies of electricity.

C. Other Technical Issues raised about reliability implications of EPA's 2023 Proposal

In addition to the broader, thematic issues discussed in the prior section, several other technical reliability-related issues have been raised in stakeholder comments.

For example, although critics acknowledge that EPA discusses resource adequacy issues, EPA has been criticized for not having modeled or sufficiently accounted for *operational reliability* issues in considering the feasibility of the implementation of the proposed rule.[95]

NERC defines these two major reliability concepts in the following way: Resource adequacy is "'[t]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.'" By contrast, operational reliability, or system security, requires "[o]perating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."[96]

Resource adequacy considerations indeed differ from operational reliability ones, but EPA has not erred in modeling only the former. It is not reasonable to expect that at this point in time EPA should have modeled operational-reliability outcomes for the nation – that is, prior to actual promulgation of standards that (a) require state implementation plans to be developed, (b) require compliance obligations no earlier than 2030, and (c) allow for flexibility in owners' decisions about how to comply with the eventual standards and SIPs.

It would be unrealistic to expect that EPA (or even anyone with operational responsibility for the grid) to know the specific future compliance decisions of power plant owners that would be required to conduct meaningful detailed system impact studies across all regions of the country affected by the new standards starting nearly a decade from now. Operational security studies are location specific and quite granular in form. Given the long lead times available in the proposed regulatory approach, power plant owners will need to make decisions about technology and/or fuel choices, and/or whether to retire a unit or operate it at a low capacity factor in future years and when many other changes have occurred on the grid, in electricity markets, and so forth. Moreover, EPA has provided the types of flexible compliance options and timing runways that will allow decision makers about specific power plants' compliance to explore such operational security considerations at the time and location when they are most relevant.

Other commenters have raised concerns about the performance characteristics of different types of generating resources as assumed by EPA in its analyses.[97] Certainly, different generating technologies operate in different

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[95] See, for example, PGen Comments.

[96] Paul Hibbard, Susan Tierney and Katherine Franklin, "Electricity Markets, Reliability and the Evolving Power System," June 2017, page 42, https://www.analysisgroup.com/globalassets/content/insights/publishing/ag_markets_reliability_final_june_2017.pdf, citing NERC's glossary of terms, available at http://www.nerc.com/files/glossary_of_terms.pdf.

[97] For example, a criticism is that technologies like wind or solar projects cannot be counted on to meet peak demand and thus have a lesser value from a resource adequacy point of view. PGen Comments; NRECA Comments.

modes, with combinations of characteristics – start-up and ramping speeds, fuel that is on-site (e.g., nuclear or conventional hydro) or subject to just-in-time delivery (e.g., natural gas) or tied to natural conditions (e.g., windiness or solar radiation), and so forth. Operational reliability depends on complex factors that system operators and electric companies bring to bear in real time, as my colleagues and I have previously explained:

> System operations are affected in real time by several things:
>
> - The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
> - The continuous variations in system conditions (e.g., variations in load as consumption changes; the sudden loss of a power plant or transmission line; changes in ambient conditions or sudden power outages due, e.g., to a storm); and
> - The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.
>
> System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or "contingencies" – such as sudden and unexpected loss of generation, transmission, or load. System planners and operators must ensure that the technical capabilities of the mix of resources on the power system are capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system - such as a cascading outage covering one or more regions - that can come from unacceptable variations in system voltage and frequency….
>
> Importantly, system security, or operational reliability, does not result from a singular condition, such as the percentage of a system's capacity that operates in "baseload" mode. To maintain operational reliability, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis. The difficulty of this task largely results from several things, and occurs along different time frames.

In the end, on-the-ground reliability will result from a combination of technologies with different attributes (e.g., capacity, energy production, capacity factors, dispatchability, fuel delivery, ramping speed, ability to provide voltage support, and so forth). Operational reliability depends upon the attributes of thousands of physical elements of and market conditions affecting the bulk power system and local electricity distribution systems.

Some commenters[98] have argued that EPA has assumed an inappropriate "replacement rate" in modeling when renewable resources replace capacity lost when coal unit retire. While it is certainly the case that wind or solar

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[98] PGen Comments.

facilities do not replace the combination of energy and capacity of some other types of technologies, such as nuclear plants, with their typical 90-percent capacity factors, or particular coal-fired or gas-fired generating units that have similarly high current capacity factors, there are many existing fossil units where extremely low capacity factors and fuel-delivery considerations (e.g., absence of firm gas pipeline delivery arrangements) suggest that it would be reasonable to presume a priori a "standard" replacement ratio across these technologies.

The more important consideration in modeling is to identify the amount of capacity AND energy that needs to be replaced on a system when determining what is needed upon the retirement of a unit with a particular operating profile (e.g., whether it is dispatchable with around the clock output capability and without fuel delivery constraints, versus an intermittent resource available either when its wind or solar energy source is available or when its electrical output can be combined with storage to provide dispatchable service subject to the operating constraints of the storage system). The availability of wind and solar output (e.g., capacity factor; capacity reliably available at the time of system peak) will depend upon a number of factors, such as the quality of the wind or solar resource, the height of towers, the age of the facility, the tilt of solar panels, the size of the solar installation). Capacity values are under review (and will continue to need to be assessed over time), not just of intermittent resources but also for resources that depend upon just-in-time deliveries of fuel (e.g., gas-fired power plants that require deliveries during extreme weather events).

EPA's analysis has been careful to provide reasonable estimates of future system conditions, and moreover the agency's design of the proposed rule provides many options for reasonable accommodation of and support for electric reliability considerations.

Attachment 1: Tierney et al., Reliability Tools and Practices (2015)

Susan Tierney, Paul Hibbard and Craig Aubuchon,

"Electric System Reliability and the EPA's Clean Power Plan: Tools and Practices,"

February 2015

Report link:
https://www.analysisgroup.com/globalassets/content/insights/publishing/electric_system_reliability_and_epas_clean_power_plan_tools_and_practices.pdf

Electric System Reliability and EPA's Clean Power Plan: Tools and Practices

Analysis Group
Susan Tierney
Paul Hibbard
Craig Aubuchon

February 2015

Acknowledgments

This report provides a primer on various reliability issues facing the electric industry as it looks ahead to implementation of the Clean Power Plan, as proposed by the U.S. Environmental Protection Agency on June 2, 2014.

Taking into consideration the many comments of various parties filed on EPA's proposal, the report addresses issues that the nation and the electric industry need to address in order to simultaneously meet electric system reliability and carbon-emissions reduction obligations.

This is an independent report by the authors at the Analysis Group, supported by funding from the Energy Foundation.

The report, however, reflects the analysis and judgment of the authors only.

About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including: energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

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Executive Summary

Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability.

Such warnings are common whenever there is major change in the industry, and play an important role in focusing the attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.

Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan.

In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.

The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed.

The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out.

http://imgkid.com/checklist-icon.shtml

Among other things, these "business-as-usual" procedures include:

- Assigning specific roles and responsibilities to different organizations, including regional reliability organizations, grid operators, power plant and transmission owners, regulators, and many others;
- Planning processes to look ahead at what actions and assets are needed to make sure that the overall system has the capabilities to run smoothly;
- Maintaining secure communication systems, operating protocols, and real-time monitoring processes to alert participants to any problems as they arise, and initiating corrective actions when needed; and
- Relying upon systems of reserves, asset redundancies, back-up action plans, and mutual assistance plans that kick in automatically when some part of the system has a problem.

http://www.bls.gov/ooh/installation-maintenance-and-repair/line-installers-and-repairers.htm

As proposed by EPA, the Clean Power Plan provides states and power plant owners a wide range of compliance options and operational discretion (including various market-based approaches, other means to allow emissions trading among power plants, and flexibility on deadlines to meet interim targets) that can prevent reliability issues while also reducing carbon pollution and cost.

EPA's June 2014 proposal made it clear that the agency will entertain market-based approaches and other means to allow emissions trading within and across state lines. Examples include emissions trading among plants (e.g., within a utility's fleet inside or across state lines), or within a Regional Transmission Organization (RTO) market. In this respect, the Clean Power Plan is fundamentally different from the Mercury and Air Toxics Standard (MATS) and is well-suited to utilize such flexible and market-based approaches. Experience has shown that such approaches allow for seamless, reliable implementation of emissions-reduction targets. In its final rule, EPA should clarify acceptable or standard market-based mechanisms that could be used to accomplish both cost and reliability goals.

Moreover, EPA has stated repeatedly that it will write a final rule that reflects the importance of a reliable grid and provides the appropriate flexibility.[1] We support such adjustments in EPA's final rule as needed to ensure both emissions reductions and electricity reliability.

Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding *in parallel*.

Some of the cautionary comments are just that: calls for timely action. Many market participants have offered remedies (including readiness to bring new power plant projects, gas infrastructure, demand-side measures, and other solutions into the electric system where needed).[2] Indeed, this dynamic interplay is one reason why a recent survey of over 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and either supported EPA's proposed current emissions reduction targets or would make them more stringent.[3]

We note many concerns about electric system reliability can be resolved by the addition of new load-following resources, like peaking power plants and demand-side measures, which have relatively short lead times.[4] Other concerns are already being addressed by ongoing work to improve market rules, and by infrastructure planning and investment. A recent Department of Energy (DOE) report found that while a low-carbon electric

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[1] See, for example, the January 6, 2015 blog post of Janet McCabe, EPA's Acting Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/. Also, see EPA's October 2014 Notice of Data Availability (NODA) that sought comments on, among other things, the potential to change the phase-in of emissions reductions to accommodate, for example, any constraints in natural gas distribution infrastructure, or how states could earn compliance credits for actions taken between 2012 and 2020.

[2] Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided through planning and infrastructure – we do note that serious questions have been raised about the assumptions used in recent reliability assessments performed by the North American Reliability Corporation (NERC). For example, Brattle Group's February 2015 report found that NERC failed to account for how industry is likely to respond to market and operational changes resulting from the Clean Power Plan. See Jurgen Weiss, Bruce Tsuchida, Michael Hagerty, and Will Gorman, "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," The Brattle Group, February 2015.

[3] The same survey found that utility executives believe that distributed energy resources offer the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, "2015 State of the Electric Utility Survey Results," January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned and municipal utilities, and electric cooperatives.

[4] Our report provides typical timelines for various types of resource additions in Section II.

system may significantly increase natural gas demand from the power sector, the projected incremental increase in natural gas pipeline capacity additions is modest (lower than historic pipeline expansion rates), and that the increasingly diverse sources of natural gas supply reduces the need for new pipeline infrastructure.[5]

Some other comments raise the reliability card as part of what is – in effect – an attempt to delay or ultimately defeat implementation of the Clean Power Plan. We encourage parties to distinguish between those who identify issues and offer solutions, and those who (incorrectly) suggest that reducing carbon pollution through the Clean Power Plan is inconsistent with electric system reliability.

In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

There are many capable entities focused on ensuring electric system reliability, and many things that states and others can do to maintain a reliable electric grid.

First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has for decades successfully relied on to maintain reliability, even in the face of sudden changes in industry structure, markets and policy.

Second, states should take advantage of the vast array of tools available to them and the flexibility afforded by the Clean Power Plan to ensure compliance is obtained in the most reliable and efficient manner possible. Given the interstate nature of the electric system, we encourage states

Entities with roles to play as part of ensuring electric system reliability and timely compliance with EPA's Clean Power Plan	
Electric Reliability Entities	Federal Energy Regulatory Commission (FERC)
	North American Electric Reliability Corporation (NERC)
	Regional Reliability Organizations
	Electric System Operators and Balancing Authorities
Other public entities	Environmental Protection Agency (EPA)
	States (air agencies, public utility commissions, energy offices, state legislatures)
	Other federal agencies (Department of Energy, Energy Information Administration)
Entities involved with markets, resource planning, procurements	Wholesale market administrators
	Electric utilities (investor-owned, municipal utilities, cooperatives, joint action agencies
Other organizations that have a role to play	Non-utility generating companies and providers of other technologies
	Interstate natural gas pipeline companies (and storage suppliers)
	North American Energy Standards Board (NAESB)
	Energy efficiency program administrators
	Others

[5] U.S DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.

to rely upon mechanisms that facilitate emission trading between affected power plants in different states. Doing so will increase flexibility of the system, mitigate many electric system reliability concerns, and lower the overall cost of compliance for all.[6]

In this report we identify a number of actions that the Federal Energy Regulatory Commission (FERC), grid operators, states, and others should take to support electric system reliability as the electric industry transitions to a lower-carbon future. We summarize our recommendations for these various parties in tables at the end of our report.

In the end, the industry, its regulators and the States are responsible for ensuring electric system reliability while reducing carbon emissions from power plants as required by law. These responsibilities are compatible, and need not be in tension as long as all parties act in a timely way and use the many reliability tools at their disposal.

We observe that, too often, commenters make assertions about reliability challenges that really end up being about cost impacts. Although costs matter in this context, we think it is important to separate reliability considerations from cost issues in order to avoid distracting attention from the actions necessary (and feasible) to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers.

Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs. There is no reason to think that cost and reliability objectives cannot be harmonized within a plan to reduce carbon pollution.

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[6] As we will discuss in a series of regional reports, others have already identified that regional strategies will minimize overall compliance costs. For example, the Midcontinent Independent System Coordinator (MISO) estimated that a regional carbon constraint approach could save up to $3 billion annually relative to a sub-regional or individual state approach. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014. See also, "Statement of Michael J. Kormos, Executive Vice President – Operations, PJM Interconnection, FERC Docket No. AD15-4-000, Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure," February 19, 2015.

This paper is designed to:

- Describe the changes underway in the industry which set the stage for the continued evolution of reliability tools and practices;
- Provide a "reliability 101" primer to describe what "electric reliability" means to system planners and operators, and why specific standard practices are so important to assuring electric reliability;[7]
- Summarize reliability concerns expressed by various stakeholders;
- Explain the ways that standard operating procedures can address these concerns; and,
- Recommend actions that can be taken by various actors in the electric industry to assure that the Clean Power Plan's goals do not undermine reliable power supply.

Our recommendations can be found in tables following the Executive Summary.

[7] This report also includes a glossary of acronyms used in our report.

Recommendation Tables

Table 1
Key Players in the Clean Power Plan and Available Tools

Entities	Roles and Responsibilities
Entities with direct responsibility for electric system reliability	- FERC (under the Federal Power Act (FPA)) - NERC (as the FERC-approved Electric Reliability Organization under the FPA) - Regional Reliability Organizations (RROs) - System operators and balancing authorities (including Regional Transmission Organizations (RTOs) and electric utilities) - States (for resource adequacy)

Other public agencies with direct and indirect roles in the Clean Power Plan	- U.S. Environmental Protection Agency (EPA)
	- State executive branch agencies:
	  - Air offices and other Environmental Agencies
	  - Public Utility Commissions (PUCs)
	  - Energy Offices
	  - Public authorities (e.g., state power authorities)
	- State governors and legislatures
	- U.S. Department of Energy (DOE)
	- Energy Information Administration (EIA)

Owners of existing power plants covered by 111(d) of the Clean Air Act	- Electric utilities
	  - investor-owned utilities
	  - municipal utilities
	  - electric cooperatives
	  - joint action agencies
	- Non-utility power plant owners

Markets and Resource Planning/ Procurement Organizations	- Organized markets administered by RTOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP).
	- Electric utilities with supply obligations & subject to least-cost planning processes:
	  - Many utilities (including joint action agencies) operate under requirements to use a combination of planning and competitive procurements (with or without self-build opportunities
	  - Transmission owners also have transmission planning requirements
	- Private investors (including non-utility companies) responding to market signals and seeking to develop/permit/construct/install/operate new resources (including new power plant projects, demand-response companies, merchant transmission companies, rooftop solar PV installation companies, etc.)

Others	- North American Energy Standards Board (NAESB) for setting electric & gas standards - Administrators/Operators of CO_2 allowance-trading systems - Administrators/Operators of energy efficiency programs - Fuel supply and delivery companies (gas pipeline and/or storage companies; gas producers; coal producers; coal transporters) - Energy marketing companies - Emerging technology providers – including, e.g., storage system providers, companies providing advanced communications and "smart" equipment, etc.

Table 2
FERC, NERC, and RROs' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
FERC: - Adoption of federally-enforceable reliability requirements and standards - Oversight of NERC and all bulk power system operators - Oversight of interstate natural gas pipeline owners/operators, with authority to approve interstate pipeline expansions - Authority over transmission planning, tariffs, open-access - In organized markets, authority over market rules (including capacity markets, provision of ancillary services providing various attributes to system operators) - Interagency coordination with EPA, DOE	Consider: - Requiring NERC, RROs, and system operators/balancing authorities to periodically assess potential reliability impacts of CPP with geographic scope appropriate to the reliability entity. The assessments could identify specific concerns, and develop backstop solutions – Preliminary assessments starting at end of 2015/early 2016, to inform state action taking into account known policy, practices, resources in the relevant area – Reliability assessments at the time of proposed state plans – Reliability assessments annually up through early 2020s - Continuing to evaluate the adequacy of current FERC gas/electric coordination policies in light of *incremental* changes resulting from CPP relative to trends already underway in the industry - Eliciting filings from RTOs and other transmission companies about any new planning tools, notice provisions for potential retirements, information reporting, new products, minimum levels of capability with various attributes - Inquiring into new natural gas policies to support wider interdependence with electric system reliability (e.g., incentives for development of gas delivery/storage infrastructure) - Working with states to consider mechanisms to afford bulk-power system grid operators' greater visibility into generating and demand-side resources on the distribution system - Providing guidance outlining compliance strategies that would require approvals of the FERC under the FPA (versus approaches that might not require such)
NERC – Reliability Standards, compliance assessment, and enforcement – Annual & seasonal reliability assessments – Special reliability assessments	Consider: – Continuing to conduct special assessments of impact of CPP on reliability (as it periodically does for other developments in the industry) – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+) – Assess whether any new standards relating to Essential Reliability Services need to be modified in light of electric system changes occurring as part of the industry's response(s) to CPP
Regional Reliability Organizations – Annual & seasonal reliability assessments – Special reliability assessments – Coordination with neighboring RROs	Consider: – Conducting special assessments of impact of CPP on reliability – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+)

Table 3
Grid Operators' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

System Operators and Balancing Authorities
– On-going annual & seasonal reliability assessments, including transmission planning
– Special reliability assessments
– Coordination with neighboring systems
 	
Note: Some of these entities also fulfill market, resource planning and procurement functions (described further below)
	Consider
	– Conducting special assessments of impact of CPP on system reliability
	  – Preliminary assessments in parallel with final rule development (in 2015) and development of State Plans (2015/2016)
	  – Final assessments upon finalization of State Plans (2016+)
	– Identifying specific areas of concern (e.g., notice period for potential unit retirements; need for more routine anticipatory analyses in transmission planning to explore "what if" changes occur on the system; identification of zones with violations of reliability requirements and any specific units needed for reliability pending resolution of the violation)
	– Working with stakeholders (including environmental agencies in relevant states) to develop proposals for reliability safety value to ensure mechanism to fully offset CO_2 emission impacts when use of a safety valve is triggered
	– Working with counterparts in natural gas industry to harmonize business practices, develop improved inter-industry forecasting tools, coordinate operating days/market timing, share information, identify specific natural gas infrastructure needs
	– Refreshing policies and practices to assure technology-neutral and competitively neutral means for providing reliability services (both resource adequacy and system operations)
	  - Technology neutrality should recognize the different attributes needed for essential reliability services, but be supportive of generation, transmission and demand-side solutions for providing such attributes
	– Working with state officials and distribution utilities within their relevant geographies to explore ways to expand the visibility (e.g., through communications and information systems) of the system operator into distribution system resource operations (i.e., distributed variable resources such as solar PV); incorporate into planning activities
	– Continuing to improve meteorological forecasting capabilities

Table 4
Other Federal Agencies' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

EPA
- **Issuing the final Clean Power Plan regulation**
- **Responsibility for finalizing standards for new power plants (Section 111(b))**
- **Responsibility for administering federal air, water, and waste pollution standards**
	Consider:
	- Clarifying acceptable standard market mechanisms that could be used to accomplish emission-reduction and reliability goals in economically efficient ways
	- Providing guidance on allowing one or more forms of a reliability safety valve, *with the condition* that overall emissions over the interim period (e.g., 2020-2029) are equal to or better than the plan without a triggering of the reliability safety valve. Examples might include:
	  - Allowing the reliability safety valve as proposed by the RTO/ISO Council (with the noted CO_2 emissions offset condition)
	  - Requiring/allowing temporary exemptions/modifications of timing/quantity requirements in State Plans
	  - Providing guidance about how states may propose to alter compliance deadlines/requirements where needed for reliability, should such issues arise over time
	- Requiring States to include reliability assessments in final State Plans (not for EPA to review/approve, but rather to ensure that such studies are conducted)

Other federal agencies - **DOE** - **EIA**	Consider: - Investigating additional reporting requirements by members of the industry - Conducting studies and analyses that examine physical capabilities of more integrated gas and electric system - Identifying CPP compliance issues as qualifying for DOE Critical Congestion Areas and Congestion Areas of Concern, and/or "national interest electric transmission corridors" under the Energy Policy Act of 2005

Table 5
States' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

States
– Air agency:
  – obligation to submit State Plans to EPA
  – reviewing/approving any modification to air permits of affected generating units
– Executive and legislative responsibility for energy, environmental laws and regulations
– Oversight over regulated electric and natural gas utilities (public utility commissions) – including ratemaking, programs (e.g., energy efficiency), planning and resource procurement
– Coordination with neighboring states
– Engagement in regional planning, operational, and market rules and procedures
– Siting/permitting of electric energy infrastructure and local gas distribution facilities
	Consider:
	– Proactively (i.e., now) engaging with state utilities and state/regional system operators in evaluation of potential CPP reliability impacts, and identification of reliability solutions (including supporting preliminary assessments in parallel with development of State Plans (2015/2016), and final assessments upon finalization of State Plans (2016+))
	– Establishing as part of the State Plan an annual state reliability evaluation, and identification of/commitment to take steps and measures in the future in response to any identified reliability concerns. This could include a framework for allowing compliance waivers and extensions in the early years in the event that reliability issues arise circa 2020, combined with requirements on state and/or compliance entities for provisional CO_2 reductions over transition period to make up for waivers/extensions in early years (e.g., to arrive at same cumulative emissions over the period)
	- Incorporating conditions in air permits to reflect operating limits (e.g., total emissions within an annual period)
	- Creating flexible implementation plans (e.g., mass-based models) and multi-state programs (e.g., regional cap/trade) to mitigate potential reliability impacts and operational flexibility across regions that reflect the normal operations of interconnected electric system
	  - State or regional cap and trade programs
	  - "Bubbling" of requirements across units owned by common owner (e.g., within one state or across states through bilateral state agreements/MOUs)
	– Developing statewide policies and measures for compliance that support reliability (energy-efficiency/renewable energy programs, including measures beyond Investor Owned Utility funded programs), for example:
	  – Clean energy standards
	  – Investment in emerging or early-stage technologies (*e.g.*, storage), public-private partnerships, tax and investment credits
	  – Protocols for counting Energy Performance Savings Contracts in State Plans
	– Reviewing need to modify permitting/siting regulations to accommodate dual-fuel capability of gas-fired power plants
	– Reviewing need to modify administrative or procedural measures to expedite siting, zoning, permitting of needed energy infrastructure (renewables, other power plants, transmission, LNG storage)
	– Instituting new entities (e.g., natural-gas buying authorities) to serve as contracting entity to support long-term commitments that may be necessary for gas system expansion
	– Requiring longer advance notice of power plant retirements

Table 6

Organized Markets' & Electric Utilities Potential Actions to Address Reliability Issues

Entities Involved with Markets, Resource Planning, and Procurements	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

Wholesale Market Administrators (Generally, Bulk Power System (BPS) Operators in Competitive Market Regions)
– **Markets designed and administered to minimize costs *subject to the constraint* that all reliability requirements of the system are met**
	Consider:
	– Adding technology-neutral and competitively neutral market rules/products to add incentives for new reliability attributes.
	  – Local (zonal/load pocket) capacity and energy market pricing; changes to scarcity pricing
	  – Reliability attributes for system security (greater quantities of spinning or non-spinning reserves; AGC; ramping/load-following; reactive power; on-site fuel; frequency response; black start capability)
	– Establishing or clarifying, where necessary, expectations around unit performance during shortage or scarcity conditions
	– Clarifying how normal dispatch processes incorporate current restrictions on unit operations (including emissions limits, ramping periods, etc.), and how similar operational restrictions (if any) resulting from Clean Power Plan compliance would be incorporated in system operations
	– Establishing or clarifying, where needed, provisions for the creation of reliability must run (RMR) contracts for generators needed for reliability that would otherwise retire – conditioned upon permit restrictions that account for CO_2 emissions offsets
	– Establishing or clarifying, where needed, procedures to minimize duration of RMR contracts through development of utility or market responses (generation, transmission)
	– Identifying any changes in forward capacity markets for the period starting in 2020

Vertically-Integrated Utilities, Cooperatives, Municipal Light Companies
– **Long-term resource planning**
– **Obligation and opportunity to develop and obtain cost recovery for necessary demand, supply, and transmission investments and expenses**
– **Obligation to maintain power system reliability**
– **In some states, integrated resource planning and/or resource need/procurement processes**
– **Coordinated operation of systems with neighboring utilities**
	Consider:
	– Conducting forward-looking assessments of potential impacts on system reliability of CPP implementation
	  – Preliminary assessments prior to and during final rule development and SIP implementation
	  – Final assessments upon finalization of SIP
	– Developing or expanding long-term integrated resource planning processes for timely and practical incorporation of CPP compliance requirements
	– Incorporating all potential short- and long-term measures (supply and demand; generation and transmission) to address significant changes during CPP transition period
	– Engaging in coordination with neighboring utilities around local reliability concerns tied to CPP implementation

Table 7
Other Organizations' Potential Actions to Address Reliability Issues

Other Organizations that have a Role To Play in Assisting in Reliable and Effective Industry Compliance	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
Non-Utility Generating Companies	Consider: - Responding to signals in organized wholesale markets and in response to competitive solicitations by electric utilities
Interstate Natural Gas Pipeline Owners/Operators – Coordination among NGP owners/operators – Coordination with BPS operators – Development of new pipeline capacity	Consider: – Improving coordination with system operators – e.g., harmonize standards and practices, coordinate operating days/market timing, share information, etc.
NAESB - Working with industry stakeholders to develop standards for operations in electric and gas industry	Consider: – Periodically convening industry sector discussions about continuing need to harmonize standards in the electric and gas industries
Administrators of Allowance Trading Programs (e.g, RGGI, California, new ones)	Consider: - Establishing new "plug and play" programs that allow states to join with relatively administrative ease
Administrators of Energy Efficiency Programs	Consider: - Establishing products to offer to generating companies to 'purchase' program credits to offset emissions, subject to strict measurement and verification
Energy Service Companies (ESCos)	Consider: - Working with State agencies to develop mechanisms to incorporate energy-savings-performance contracts into State Plans

I. Context

In June 2014, the U.S. Environmental Protection Agency (EPA) issued its proposed Clean Power Plan, designed to reduce carbon dioxide (CO_2) emissions from existing fossil-fuel power plants in the United States. The final rule, which is now anticipated to come out in mid-2015, will require each of the 49 states with covered power plants to prepare and submit plans for how they propose to reduce emissions from the plants in their state. Although the features of the final regulation will undoubtedly change in light of the many comments filed, EPA's current proposal requires states and affected electric generating units (EGUs) to demonstrate progress to reduce emissions starting in 2020, with subsequent reductions thereafter. This new policy will eventually affect over half of the nation's generating capacity and all but the smallest fossil fuel generating units.[8]

In light of the broad scope of the regulation, many stakeholders have raised concerns about whether EPA's proposal will jeopardize the reliability of the electric system. In Washington, in state capitols, in media alerts, in comments filed at the EPA, and elsewhere, many public officials, electric utilities, industry reliability organizations, and others have been demanding

[8] An affected electric generating unit (EGU) is defined broadly, as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input and (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system (Proposed Rule, Federal Register, Vol. 79, No. 117, June 18, 2014, page 34854). Generating units estimated to be subject to EPA's Clean Power Plan:

SNL Financial (as of 2-2015)	Generating Units Likely to be Directly Covered by Section 111(d)*		Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as Share of Total Capacity (%)
	(# Units)	Summer Capacity (GW)	Summer Capacity (GW)	Summer Capacity (GW)
Coal	922	300	303	99%
Gas	2,137	334	464	72%
Oil	62	17	39	44%
Total Fossil	3,121	651	806	81%
All Capacity			1,151	57%

* Includes all existing or under development steam turbines and combined cycle units greater than 25 MW, and any natural gas combustion turbines with generation greater than 219,000 MWh.
Source: SNL Financial, Power Plant Unit Database.

that the changes introduced by the Clean Power Plan not come at the expense of electric reliability.[9]

For many decades, such cautions have appeared whenever major events – such as major new environmental regulations affecting power plants or structural changes to introduce competition in the electric industry – occur that could affect electric system reliability.[10]

Indeed, well before the EPA issued its proposal, various reliability organizations had already begun to anticipate how changes underway in the electric industry would necessitate modifications in traditional ways to plan for and operate the electric system. For example, the North American Electric Reliability Corporation (NERC) – the nation's electric reliability standards organization – issued a "concept paper" in October 2014, in which NERC describes the many ways that today's reliability procedures will need to evolve to keep ahead of the changing character of the electric "resources" that connect with the grid.[11]

NERC's paper, which was in development well before the EPA issued its Clean Power Plan (and is different from NERC's November 2014 assessment relating to the EPA proposal), begins by recognizing that the

> North American BPS [bulk power system] is experiencing a transformation that could result in significant changes to the way the power grid is planned and operated. These changes include retirements of baseload generating units; increases in natural gas generation; rapid expansion of wind, solar, and commercial solar photovoltaic (PV) integration; and more prominent uses of Demand Response (DR) and distributed generation…. As the overall resource mix changes, all the aspects of the ERSs [Electric Reliability Services] still need to

[9] See discussion in Section III and the Appendix to this paper. Note that even the leadership of the EPA and the President of the United States have insisted upon design and implementation of the Clean Power Plan in ways consistent with electric system reliability. See, for example: President Obama's Presidential Memorandum ("Power Sector Carbon Pollution Standards," June 25, 2013), in which the President directed the EPA to issue regulations to control CO_2 emissions from the power sector, and included the following instructions: "In developing standards, regulations, or guidelines … [EPA] shall ensure, to the greatest extent possible, that you: …(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses…" Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards

Also, see: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; and the January 6, 2015 blog post of Janet McCabe, EPA's Acting Assistant Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/.

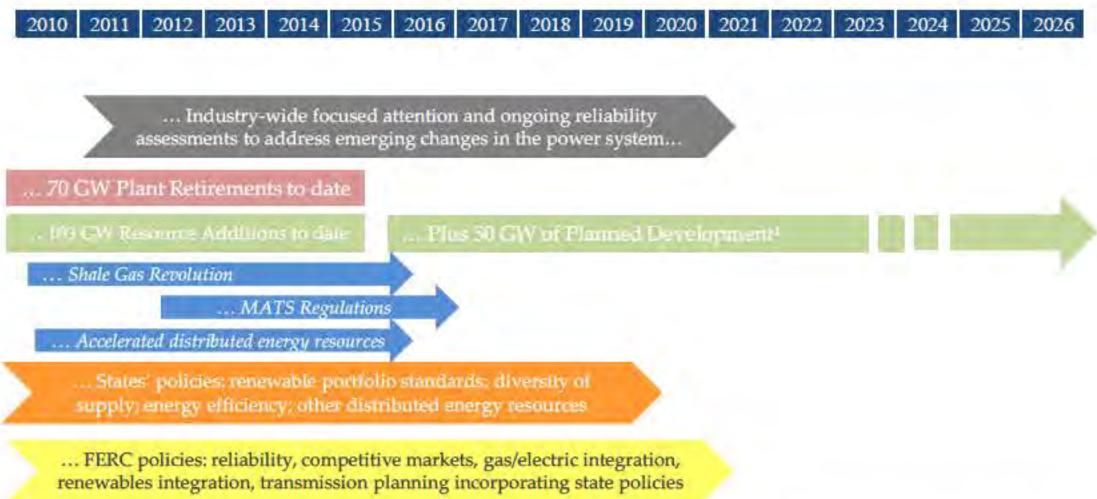
[10] Notably, this has occurred in conjunction with: the EPA "NO_x SIP call" which affected 23 states in the 1990s; state and federal policies related to electric industry restructuring in the 1990s: the Cross-State Air Pollution Rule (CSAPR) and MATS rule; and with on-going increases in the amount of distributed energy resources and intermittent/non-dispatchable resources on the grid.

[11] NERC, "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability," October 2014. Hereinafter referred to as "NERC Essential Reliability Services Report".

be provided to support reliable operation. ERSs are technology neutral and must be available regardless of the resource mix composition.[12]

Those transformations have been in the works for years – in part as a result of the shale gas revolution, changes in the relative prices of fossil fuels, state policies and federal laws encouraging greater use of renewable energy and energy efficiency, declines in wind and solar technology costs, retirements of old and highly polluting coal plants, retirements of a handful of nuclear plants (in some cases for safety reasons, and others for economic reasons), and strong interest by many customers in exploring ways to better manage their own energy use.[13] We depict these changes occurring in parallel in Figure 1, below.

Figure 1
Timeline of Changes Underway in the Electric Industry



[1] Includes retirements/additions announced for 2015 and units that are mothballed or out of service. Planned units include those under construction or in advanced development. Source for MW of retirements and planned additions: SN Financial, Accessed February 2015

As always, grid operators and utilities have implemented and adjusted long-standing planning and operational practices to stay abreast of, understand, and adapt practices to address reliability issues related to such changes in the industry. Given the multiple pressures on the electric power sector, such actions would be needed today even if EPA had not proposed to control carbon pollution in the Clean Power Plan.

[12] NERC Essential Reliability Services Report, page iii. The scope of work for this report was adopted by NERC in March of 2014, before the EPA Clean Power Plan was issued in proposed form in June, 2014.

[13] See, for example: Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 8, 2014, pages 23-46.

Indeed, many organizations besides NERC have also been flagging the need to address reliability issues as the industry undergoes significant change. For example:

- The Federal Energy Regulatory Commission's (FERC) attention to gas-electric coordination as the two industries become increasingly dependent on each other,[14] and transmission companies and Regional Transmission Organizations (RTOs) plan for integration of variable generating resources and transmission requirements driven by public policies of state and local governments;[15]
- Studies by the Midcontinent ISO (MISO) of gas infrastructure,[16] and MISO's support for policies addressing transmission implications of the region's growing quantities of wind and other renewable resources;[17]
- ISO-New England's (ISO-NE) continuing analysis of that region's deepening reliance on gas-fired generating facilities, near-term generator retirements, and need to integrate deepening amounts of renewable resources;[18]

[14] FERC Commissioner Philip Moeller first requested comments on gas-electric coordination in February 2012. Since that time, the FERC has held nine regional conferences to address the issue. See FERC "Natural Gas – Electric Coordination." Available: http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp for additional detail. In 2013, FERC Chairman Cheryl LaFleur and Commissioner Moeller testified before Congress on "The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges". The Commissioners noted that gas-electric coordination was and is a growing and important trend due to falling natural gas prices and substantial domestic supplies. FERC receives quarterly updates from its staff on the status of developments in the industry regarding gas/electric coordination issues. http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp. Note too that in response to a directive from FERC, the North American Energy Standards Board (NAESB) undertook a process to develop some new standards for both electric and natural gas industries, which were described in a report submitted to FERC on September 29, 2014.

[15] On July 21, 2011, FERC issued Order 1000 (Docket No. RM10-23-000), in which the agency required, among other things, that each public utility transmission provider: (1) participate in a regional transmission planning process that produces a regional transmission plan; and (2) consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs. FERC Fact Sheet, Order 1000, http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf. On June 22, 2012, FERC issued the final rule in its docket (RM10-11-000) on Integration of Variable Energy Resources, in which it ordered a number of changes in interconnection agreements, transmission tariffs and cost recovery for regulation reserves to better accommodate renewables reliably and efficiently. 139 FERC ¶ 61,246, FERC Order No. 764.

[16] MISO released its first gas-electric interdependence study in February 2012; it reviewed existing gas pipeline capacity to serve existing electric generation and additional capacity that could be added in the future, and signaled to the MISO and stakeholders that an increase in gas-fired generation will require an "improved collaborative process between pipelines, power generators, and regulators to coordinate natural gas infrastructure projects." Gregory L. Peters, "Gas and Electric Infrastructure Interdependency Analysis," Prepared for the Midwest Independent Transmission System Operator, February 22, 2012, page. 12.

[17] MISO's "Multi-Value Project Portfolio Analysis" of transmission projects will support delivery of up to 41 million MWh of wind energy. Available: https://www.misoenergy.org/PLANNING/TRANSMISSIONEXPANSIONPLANNING/Pages/MVPAnalysis.aspx

[18] ISO-NE first identified these issues in 2010. In 2013, ISO-NE's Chief Executive Officer, Gordon van Welie, stated: "It is clear that resolving these challenges will not be simple, and it will take several years to realize the benefits of the solutions… It is important to remember that, often, the best ideas are born out of necessity. Today the power system faces significant and formidable obstacles. But tomorrow, it will be smarter, stronger, and more environmentally sound because of our collective efforts." ISO-NE, "2013 Regional Electricity Outlook," January 31, 2013, page 8.

- Starting in 2010, calls by the American Public Power Association (APPA) to pay greater attention to the impacts of distributed generation and increased natural gas demand for power generation;[19]
- The Electric Reliability Council of Texas' (ERCOT) ongoing analysis of wind integration as part of its bi-annual Long Term System Assessment;[20]
- The review by the five major electric utilities in California of the implications of a potential significant increase in the state's renewable portfolio standard,[21] and the California ISO's (CAISO) solicitation of more flexible resources to support integration of renewables;[22]
- PJM Interconnection's (PJM) recent capacity performance proposal, in response to concerns raised by unavailable conventional generation capacity during the 2013-2014 polar vortex;[23] and
- New York ISO's (NYISO) ongoing evaluation of reliability needs, including scenarios that account for environmental regulations, increasing penetration of renewable resources, and natural gas fuel availability.[24]

These studies and activities – and others like them – illustrate that our electric system operators, planners, regulators, and others are stepping up to the plate (as they typically do) to grapple with ways to make sure that the future electric system is as reliable as the one we count on today. And their analyses reflect the reality that these trends are occurring as a result of economic, policy and regulatory forces that are independent of EPA's Clean Power Plan.

The value of such "reliability alerts" is that they identify ways in which changes in policy, economics, technology, and law affecting the electric industry intersect with the physics and engineering of interconnected electric systems. All parts of the system must pay attention to certain imperatives of the others.

[19] See, for example, Aspen Environmental Group, "Implications of Greater Reliance on Natural Gas for Electricity Generation," prepared for American Public Power Association, July 2010.; and American Public Power Association, "Distributed Generation: An Overview of Recent Policy and Market Developments", November 2013.

[20] See, for example, ERCOT, "Long-Term System Assessment for the ERCOT Region," December 2012, which examined the implications of introducing significant wind generation and new gas-fired power plants on to the ERCOT Texas system.

[21] Energy+Environmental Economics, "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

[22] California Independent System Operator Corporation Reply Comments on Workshop issues, before the Public Utilities Commission of the State of California, In the Matter of "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations." Rulemaking 11-10-023, April 5, 2013.

[23] PJM Staff Proposal, "PJM Capacity Performance Proposal", August 20, 2014.

[24] NYISO conducts a detailed "Reliability Needs Assessment" every two years. See, for example, NYISO, "2014 Reliability Needs Assessment," Final Report, September 16, 2014.

Certainly, the shale gas 'revolution' has introduced significant quantities of domestically supplied natural gas at prices which compete with coal, the historically dominant domestic fossil fuel for power generation. This new reality presents economic opportunities to the power system, with cost and environmental benefits for households and businesses. At the same time, however, lower-cost natural gas introduces new issues that must be addressed in the standards, business practices and regulation of both the electric and gas industries: for example, there are new issues surrounding ensuring adequate fuel-transportation and storage arrangements. States' policies to rely more heavily on domestic wind and solar generation also introduce new challenges: grid operators must plan to operate their systems reliably with greater reliance on less dispatchable resources (or in some cases resources that cannot be 'seen' on the system by grid operators, when the resources are behind the meters of customers).

Reliability organizations and grid operators (including NERC, Regional Transmission Organizations (RTOs), electric utilities, and others) are already facing the implications of these trends. They are doing what we count on them to do: looking ahead to see what's on the horizon and identifying reliability-related issues that require adjustments to planning, markets, or operations. They are identifying issues that arise from economic, technological, legal or policy changes. They are developing new analytic tools to better understand how factors like the weather (or wind or sun/cloud-cover conditions) affect power system operations. They are identifying possible, if not likely, changes in power supplies, and indicating where and when new resources might be needed in the years ahead. They are working with transmission owners, power plant companies, government regulators, reliability coordination organizations, consumer representatives, and others to identify changes that may be required in operating standards, market products, and practices.

This is standard operating procedure in an industry with a history with strong legal, cultural, and organizational incentives to do what it takes to make sure that a world-class reliable electric system remains a bedrock of the American economy and society. Recent calls for action to ensure that the Clean Power Plan does not jeopardize electric system reliability should be viewed in that context: people are doing their jobs, not necessarily trying to impede the Clean Power Plan.

II. What Do We Mean by "Electric System Reliability"?

What is reliability, and why does it matter?

http://www.dailymail.co.uk/news/article-2226399/Sandy-Vast-majority-ConEd-wont-power-10-days--Manhattan-hopes-lit-Saturday.html

Most electricity users think of reliability in terms of how often their power shuts off and how long it takes to get it back on. These familiar reliability annoyances typically result from events affecting the local distribution system, such as a snowstorm or hurricane knocking out power lines or a car hitting a power pole.

While critically important to electricity users,[25] such events are not the main concern of observers considering the implications of EPA's Clean Power Plan. What they worry about is whether the overall electric system can do its job, day in and day out, even if one neighborhood or another loses its power.

This other kind of reliability is known as "bulk power system"[26] reliability (and what we call "system reliability" and what insiders sometimes call "BPS" reliability). Outages due to system failures differ from local outages in fundamental ways: in how they can arise; in the geographic scope of power interruptions; in the process and timing of power restoration; in the magnitude of adverse consequences; and, in terms of the parties responsible to fix the problems. The sheer scale of potential human health, safety, and economic impacts is what separates system reliability from local reliability, and dictates a high degree of vigilance on the part of regulators and the industry to avoid system-reliability failures.[27]

[25] Electricity consumers are acutely aware of how inconvenient and costly outages can become, and of course may not care whether an outage is local or system-wide, in terms of the disruptive impacts on their lives. At the state level, maintaining reliable service is a fundamental obligation of every local utility, and state public utility commissions (PUCs) measure the performance of local utilities in maintaining local reliability over time through measurements that track the frequency and duration of outages. In many states, utilities can be fined heavily for poor reliability performance tied to local distribution-system outages. In contrast, system power failures – which are far less common – generally involve events affecting power plants and transmission lines and a wider geographic area of the grid, with reliability enforcement subject to the jurisdiction of FERC under then Federal Power Act (FPA).

[26] A Bulk Power System (BPS) generally covers a wide geographic region, and includes the generating resources, transmission lines, and associated equipment and systems used to operate the integrated electric system within the region. BPSs generally do not include the lower-voltage distribution systems of local utilities, which deliver power from the BPS to end-use customers.

[27] This is not to say that local distribution system circumstances can never create system reliability challenges. Given that the electric system has to maintain customer demand (load) and supply in balance at all times, a major storm that causes local lines to

For this reason, multiple entities (including those in Table 8) constantly monitor conditions on the overall power system to assure that the overall system operates with a high degree of reliability. System planners, reliability organizations, power companies and regulators look many years ahead, to analyze changing conditions and flag issues on the horizon that need attention. From one season to the next, they review whether there will be enough resources to meet peak demand. Closer to real time, system operators monitor whether power plants are out for maintenance, whether temperature conditions will produce higher than expected demand, and myriad other conditions so that they can get ready for the next day's operations. And in real time, on a second-by-second basis, grid operators have to monitor, and manage the "balance" of the system so that supply equals demand within tolerable operating limits (i.e., "frequency"). Thus, across very different time frames, many actors in the industry work to assure that the system performs with impeccable reliability levels.

Table 8
Entities Responsible for Electric System Reliability

Organization	Roles and Responsibilities
Federal Energy Regulatory Commission (FERC)	- Federal agency responsible for enforcement of electric sector reliability requirements, including oversight of the ERO (NERC)
North American Electric Reliability Corporation (NERC)	- Designated as the Electric Reliability Organization (ERO) by FERC; responsible for developing, assessing and enforcing reliability standards
Regional Reliability Organizations (RROs)	- Members of the NERC that ensure regional operations are reliable, adequate and secure. Includes: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First (RF), SERC, Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electric Coordinating Council (WECC)
Grid and System Operators, and Balancing Authorities	- Responsible for the reliability functions in specific geographic areas. In addition to many electric utilities, there are other organizations serving this function in wide geographic areas, including Regional Transmission Organizations (the New York System Operator (NYISO), PJM Interconnection, New England Independent System Operator (ISONE), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)

Those responsible range from: the federal regulators at the FERC, which has statutory authority relating to system reliability; to NERC, the nation's "Electric Reliability Organization" (ERO), authorized by FERC to set reliability standards for grid operators, utilities and other power companies; to Regional Reliability Organizations (RRO) which ensure that the system is reliable, adequate and secure within the geographic footprint for which they're responsible; to grid operators (also known as "balancing authorities" or "system operators") with the operational responsibility in smaller areas.[28] Each

go down can cause a rapid loss of demand with the immediate need to address that big imbalance on the overall system in order to avoid a bigger problem affecting many other areas of the grid. Similarly, high penetrations of distributed resources (e.g., rooftop solar panels on customers' premises) connected to the local distribution system are emerging as a reason to increase the BPS grid operator's "visibility" into what is happening at the distribution system level because of the interrelationships between the two systems. In fact, several areas with significant current or expected installation of distributed resources (e.g., Hawaii, California) have begun to evaluate potential system-wide challenges associated with such developments.

[28] NERC's Glossary of Terms formally defines the various entities, along with various terminologies that described their responsibilities. NERC, "Glossary of Terms Used in NERC Reliability Standards," January 29, 2015, available: http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf

one has different responsibilities, as shown in Table 8.

These entities monitor system reliability using time-tested, well-developed industry analytic tools. For longer-term assessments, the standard methods take into consideration a vast array of potential future infrastructure scenarios and system operational contingencies (e.g., sudden loss of generation, transmission or load). Annually and seasonally, system operators and reliability planners conduct reliability assessments to evaluate system changes, flag areas of concern that need to be addressed within different time frames, and identify plans to address any reliability concerns that may arise over the planning period. In addition, special assessments are periodically carried out in response to any industry or policy changes that have the potential to affect system reliability.

Thus it should not be surprising that EPA's proposed Clean Power Plan is being (and will continue to be) evaluated for potential reliability impacts in future years. We have seen such reliability evaluations exercised regularly over decades in the face of other major industry changes, as noted previously.[29] In every case, the prospect of change has led to reliability assessments and the waving of cautionary flags to call attention to the new challenges ahead.

How could electric system reliability be affected by the Clean Power Plan?

The Clean Power Plan will not lead to more cars hitting distribution poles, nor will it affect the frequency, location, or severity of storms that lead to local outages. The more relevant questions are how controls on power plant CO_2 emissions will affect power system components and operations. As highlighted in Section III (which summarizes stakeholder concerns around the Clean Power Plan's potential impacts on system reliability), concerns primarily relate to impacts these pollution controls will have on availability of existing power plants. Will plants

[29] There are many examples where changes in conditions have led to questions about whether the electric industry (and its supply chains) could respond in a sufficiently timely and effective way to avoid reliability problems. This occurred, for example, with: (1) prior EPA and state regulations governing human health and environmental impacts, including the CAA Title IV sulfur dioxide cap-and-trade program contained in the 1990s; the changes in National Ambient Air Quality Standards (NAAQS) and Clean Water Act (CWA) requirements; the more recent CSAPR and MATS regulations; and the proposals under 316(b) of the CWA. (2) Changes to the structure of the electric industry over the past several decades, involving major changes in the regulation of and the incentives for investment and operation; transfers of ownership and management of existing generation and transmission system elements; and the formation of RTOs and associated wholesale markets for energy, capacity and ancillary services. (3) Fundamental shifts in the economics of generating power from coal or from natural gas, driven initially by changes in technology costs (e.g., large-scale steam generators versus combined-cycle technologies) and more recently by the emergence of low-priced domestic shale gas resources; the growing strain in some regions on the capacity of interstate natural gas delivery and storage systems to meet combined demand from heating and electricity generation uses during peak winter conditions; and different business practices, and operational protocols and standards in two industries (the natural gas industry and the electric industry) that might need to be better aligned as the two industries become more interdependent. (4) The ongoing displacement of traditional generation resources by grid-connected and customer-sited variable renewable resources, in some cases dramatically changing the shape of net load that must be followed by system operators. (5) Questions about the ability of some wholesale electricity markets to provide sufficient financial incentives for suppliers to continue to operate and/or to enter the market.

retire and, if so, which ones and when? Which new ones will be added, over what time period? Will gas pipelines and other fuel-delivery infrastructure be in place in time to fuel a power system that depends more upon natural gas? Will the electric transmission system be capable of moving power generated in new locations relative to customer demand?

Insights and answers to these various questions fall into two basic categories, differentiated by time scales. One focuses on long-term planning considerations, and is called "resource adequacy": Will there be enough (adequate) resources in place when system operators need to manage the system to meet demand in the future? The other focuses on short-term operations, and is called "system security": Will the operators be able to run the system in real time in a secure way to keep the system in balance, with all that that entails technically?[30]

Resource Adequacy

First, the interconnected electric grid must have resource adequacy – that is, there must be sufficient electric supply to meet electric demand at the time of annual peak consumption, taking into account the expectation that some parts of the system will not be able to operate for one reason or another. The system must have some additional quantity of capacity above the annual peak load value (the reserve margin) to cover the possibility that in highest-demand hours some resources may be out of service due to planned or unplanned outages.[31] In some regions and sub-regions (or "zones"), constraints on the ability of the transmission system to move power from one location to another mean that some portion of the demand within the zone must be met by generating resources within that same zone.

Ensuring resource adequacy is generally accomplished through two steps. First, the expected system peak demand and energy requirements over a long-term period (e.g., ten years) are established through a comprehensive forecasting effort. Forecasting processes for this purpose use well-established economic and industry modeling tools and data, are conducted frequently, and typically involve input by utilities, grid operators, public officials, consumer advocates, and

[30] The U.S. Energy Information Administration (EIA) defines electric system reliability as the "degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service." U.S. EIA, "Glossary," available at http://www.eia.gov/tools/glossary/index.cfm?id=E.

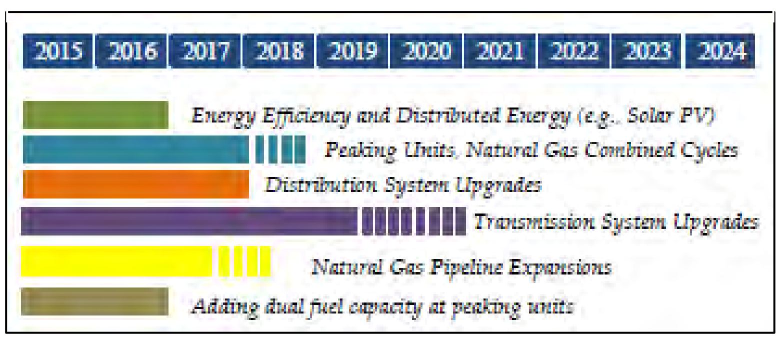
[31] Reserve margins are generally in the range of 10 to 20 percent of system peak load. The actual reserve margin varies from region to region as a function of many factors (e.g., the mix and expected performance of assets on the system, operational and emergency procedures, the availability of demand response/load curtailment, and contributions that may come from neighboring regions).

many other market participants and stakeholders. This step occurs in both wholesale energy markets and through integrated resource planning conducted by electric utilities.

Second, to the extent that identified long-term needs exceed resources expected to be on the system (due, for example, to growth in demand over time, and/or the retirement of existing resources), the deficit is met through the addition of new infrastructure (power plants or transmission lines) and/or demand resources (such as energy efficiency or demand-response measures). The ways in which new resources are added varies around the country, depending on the structure of the electric industry and the regulatory approach in place in a given state, along with other aspects of the market (including FERC-regulated RTOs in many regions). In wholesale market regions like PJM and NYISO, identified needs are met through market structures designed to provide financial incentives for investment in new capacity. In other regions (like most of the West), vertically integrated utilities, cooperatives and municipal electric companies add needed capacity by proposing and building their own project and/or through soliciting offers from other competitive suppliers. In any event, the overall resource need is forecasted (and, if relevant, a local/zonal requirement is further identified), and some combination of regulated and/or market process brings forth proposals to satisfy the need.

These processes are designed to accommodate the lead times necessary to bring a new project or resource into operation. They typically involve sufficient advance notification of need to allow for: (1) initial development stages and associated studies around project feasibility, interconnection, etc.; (2) administration of the markets or competitive procurement processes (and regulatory approvals of them); (3) zoning, permitting, and siting approvals for specific facility projects; (4) construction of the power plant and associated infrastructure (e.g., transmission interconnection/upgrades and – if needed – fuel delivery such as natural gas pipeline connections). Lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades. Figure 2 provides a conceptual depiction of lead times for planning, developing and installing

Figure 2
Typical Lead Times for Different Electric Resources



Source: Analysis Group

different types of infrastructure to support electric resource options.

The processes outlined above rarely occur in a sequential fashion.[32] Ten-year assessments take into account time periods that extend well beyond the number of years it typically takes to develop, permit, finance, and construct a new power plant.[33] As one developer is starting to scope out where to site a new power plant in anticipation of hoping to get approvals and enter the market four years in the future, another already has its approvals and has commenced construction. Installation of demand-response measures take much shorter time periods altogether. Many steps occur concurrently across many different types of resources that are being planned and put in place to meet resource adequacy requirements.

In practice, there are exceptionally few instances where industry has failed to provide for resource adequacy, where – due to a lack of installed capacity – the grid operator had to implement emergency protocols (such as lowering voltage (sometimes known as rolling brownouts) or curtailing service to customers (sometimes known as rolling blackouts)).[34] Although there have been rare occasions where a relatively near-term resource adequacy problem has been identified, regulators, market participants, grid operators, customers and reliability organizations have taken the steps needed to assure that the lights stayed on. There are well-known examples from around the country where the industry (including its regulators) did what was necessary to keep power flowing to consumers.[35] In large part, this track record

[32] For example, often initial market development of a new generating resource – e.g., site identification and control, technology selection, fuel and transmission infrastructure studies, fatal flaw analyses, even some initial siting and permitting efforts – happen in advance of or concurrent with resource need specification or market/utility procurement. Similarly, engineering, construction, and fuel contracts may be established (on a contingent basis) prior to final resource selection or final regulatory approval. Successful resource development teams effectively manage the flow of steps needed to take a new power plant from concept to operation so as to balance the stages of investment risk against the process of procurement and approval.

[33] Typically, lead times for a new natural gas power plant involve 2 years for development and permitting and another 2 years for construction. A peaking unit typically takes less time: from 2 to 3 years. Demand-response and other distributed energy resources can be brought to market in 1 to 2 years. Some generating additions may further require transmission or distribution system upgrades. These can range in time from as little as 2 to 3 years for local distribution upgrades to 5 to 6 years or longer for more extensive transmission system upgrades, but such permitting and construction activities are carried out coincident with power plant permitting and construction. Lead and development times are in part, flexible, depending on the system need and critically, it is possible to move faster when needed. For example, following the California Energy Crisis in the early 2000's, the state added thousands of MWs of new generation using a set of emergency 21-day, 4-month, and 6-month citing procedures. These emergency responses helped establish a set of best practice siting procedures that can be used by other states in similar situations. Susan F. Tierney and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[34] A notable exception is the well-known California electricity crisis of 2000-2001, which resulted from a combination of actions (including market manipulation through actions in the electric and natural gas markets, as well as caps on retail electricity prices). To our knowledge, there has never been a resource adequacy event (e.g., a brownout or blackout) due to implementation of an environmental regulation.

[35] Examples include:

- ERCOT's slim reserve margins in recent summers, including for example, in 2012, when nearly 2,000 MW of mothballed capacity was returned to service. Commissioner Anderson Jr., Public Utilities Commission of Texas, "Resource Adequacy in

reflects the existence of the many resource-adequacy processes outlined above, the presence of multiple early warning systems, the ability of policy makers to take action to address challenges when urgent action is needed,[36] and a strong mission orientation of the industry and its regulators.[37]

System Security

Even assuming that these resource adequacy processes end up ensuring there are enough megawatts of capacity in place when needed to meet aggregate load requirements, actual

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ERCOT," Update #4, January 30, 2013. Available: https://www.puc.texas.gov/agency/about/commissioners/anderson/pp/analysis_ercot_capacity_reserve_margin_013013.pdf.

- Reliability must run (RMR) contracts to keep plants operating, for example:
  - The retention of operations of the Potomac Generating Station until completion of the Pepco transmission lines; see, Paul J. Hibbard, Pavel G. Darling, and Susan F. Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011);
  - A delay in Exelon's proposed retirement of the Eddystone and Cromby generating stations in Pennsylvania after PJM determined that in the absence of transmission upgrades, retirements of those units would lead to violations of security standards, with a reliability must run agreement between PJM and Exelon and state air regulators so that the plant could remain on line pending those transmission upgrades, but with limits on the units' dispatch to only those times when the units were needed for operational reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President of Federal Regulatory Affairs and Policy, Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011.
- Construction of peaking units on a fast-track basis by the New York Power Authority: "We increased our generating capacity by about 450 megawatts during summer 2001 when we began operating small, clean natural gas-powered generating plants at six sites in New York City and one on Long Island. We had launched a crash program in late August 2000 to install these PowerNow! plants in response to warnings from officials in the public and private sectors that the New York City metropolitan area could face power shortages in the summer of 2001. Similar warnings were repeated throughout the 10 months it took to obtain, site, design and install the units—a process that normally would require more than two years." New York Power Authority, "Small Clean Power Plants," Available: http://www.nypa.gov/facilities/powernow.htm.
- Requests by ISO-NE for demand-response resources in Connecticut on a fast-track basis: "On December 1, 2003, ISO New England Inc. (ISO-NE) issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut (SWCT) for the period 2004 to 2008. The purpose for acquiring these resources was to improve the electric system reliability in SWCT through the summer of 2007, when the 345 kV transmission loop is planned for completion." J.E. Platts, ISO-NE, "Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability, 2004-2008," October 4, 2004, page iii.
- New York State's contingency planning efforts (including consideration of new transmission projects) to prepare for a possible shutdown of the Indian Point nuclear plant, shutdown as early as 2018, depending on the outcome of its re-licensing with NRC. See the New York Department of Public Service Commission Case No. 12-E-0503, "Proceeding on Motion to Review Generation Retirement Contingency Plans." Available: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0503&submit=Search+by+Case+Number

[36] Susan F. Tierney, and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[37] For example, FERC/EPA processes under the MATS regulation introduced a Reliability Safety Valve and related procedures to ensure that identified reliability challenges could be addressed, while allowing some flexibility with the eventual MATS timeline. As discussed below, the ISO/RTO council has proposed a similar reliability safety valve for the Clean Power Plan and the EPA has also acknowledged potential reliability concerns in its most recent Notice of Data Availability memorandum.

'delivered' reliability also depends on making sure that the system operates in real time with high technical integrity.

System reliability is affected in real time by several things:

- The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
- The variations in system conditions (e.g., building lights turned on, or a power plant tripping off line unexpectedly, or sudden storm-related outages, or shifts in windiness) that change on a second-to-second, minute-to-minute, hour-to-hour, and day-to-day basis; and
- The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.

System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or "contingencies" – such as sudden and unexpected loss of generation, transmission, or load.[38] System planners and operator must ensure that the mix of resources on the system is capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system – such as a cascading outage covering one or more regions – that can come from unacceptable variations in system voltage and frequency. Blackouts can damage electrical equipment on the grid and on customers' premises, and create wide-ranging safety and health impacts.

To assure system security, the system as a whole must have certain attributes allowing it to provide "essential reliability services," as summarized in Table 9. These include two functional categories:

- *Voltage support*, meaning the ability of system resources to maintain real power across the transmission grid, through the use of reactive power sources such as generators connected to the system, capacitors, reactors, etc. Voltage on the system must be

[38] NERC describes certain features of the bulk power system needed to meet system security requirements – e.g., voltage control, frequency control – as Essential Reliability Services, or ERS. NERC Essential Reliability Services Report.

maintained within an acceptable voltage bandwidth in normal operations and following a contingency on the system.[39]

- *Frequency Management*, meaning the ability of the system to maintain a system frequency within a technical tolerance at all times.[40] Frequency is a function of the match between generation output and load on the system, and requires constant balancing, or following of load by resources that can increase and decrease output instantaneously.

Importantly, system security, or operational reliability, is not a "yes" or "no" condition. To maintain it, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis.[41] The difficulty of this task largely results from several things. First, the

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[39] Voltage support is local in nature, can change rapidly, and depends in part on the type and location of generators connected to the transmission system. Typically, voltage control is maintained by system planners and operators. Acceptable power factors for voltage support are maintained, in part, through the use of reactive power devices (or power factor control) that inject or absorb reactive power from the bulk power system. Reactive power can be provided by synchronous thermal generators and through capacitors and other devices, as well as by 'adequately designed' variable energy resources (including wind and solar) and storage technology. Voltage disturbance performance is the ability to maintain voltage support and voltage control after a disturbance event. NERC Essential Reliability Services Report, pages 1, 10-11.

[40] Frequency must typically be maintained within tens of mHz of a 60 Hz target. Higher frequencies indicate greater supply, while lower frequencies typically indicate greater demand. Frequency management includes: (1) Operating reserves, which are used to balance minute to minute differences in load and demand, load following capabilities to respond to intra- and inter-hour changes in load fluctuations, and reserves, which are used to restore system synchronization following generator or transmission outages; (2) Active Power Control, including ramping capability to quickly bring generators online in response to operator needs, often in ten minutes or less; (3) Inertia, or stored rotating energy that is used to arrest declines in frequency following unexpected losses. Historically, inertia has been supplied by large coal-fired generators, although NERC notes that new 'synthetic' inertia is available through the operation of variable energy resources supported by energy storage devices; and (4) Frequency Distribution Performance, which similar to voltage distribution performance, is the ability to maintain operations during and after an unplanned disturbance. NERC Essential Reliability Services Report, pages 3-5, 8-9.

[41] System operators manage voltage and frequency as load changes over time, and in response to contingency events, through the posturing and management of the resources on the system across several time scales:

- On a second-by-second basis through automatic generation control (AGC) systems on resources that will automatically adjust generation up or down in response to system frequency signals.
- On the time scale of minutes through tens of minutes through accessing "spinning reserves," including operating resources with the ability to ramp output up or down quickly, and resources that can connect to the system within several minutes.
- On the timescale of tens of minutes through accessing longer-term reserve resources that can turn on and connect to the system in less than an hour (typically on the order of 15 to 30 minutes).
- On the time scale of hours or days by committing sufficient operating and reserve resources to manage *expected* swings in net system load (that is, system load net of variable resource output). Note that load varies in relatively 'normal' ways over the course of the days, weeks, and months, and is predictable with a relatively high degree of accuracy by system operators. This allows for the commitment and availability of enough system resources to meet reliability objectives. However, the proliferation of distribution-level, behind-the-meter (BTM) generation with variable output (e.g., distributed wind and solar PV) complicates the forecasting of "net load" visible to system operators – that is, the normal variation in load net of variable BTM output that comes and goes with the sun and wind.
- On an as-needed basis for voltage control by adjusting reactive power injected into or absorbed from the system by on-line generators, capacitors, reactors, and system var compensators.

Source: NERC Essential Reliability Services Report, generally.

operator has, in effect, a particular set of assets on the system at any time, which reflects the operational attributes of the various resources on the system at that time. These include things like: power plants with different operating profiles (e.g., start-up time, limits on output under different temperature conditions, availability to fuel supply); transmission systems that allow or limit power flows in various directions; 'smart' controls and communications devices that allow (or not) visibility into and/or management of power flows; demand response; storage systems; and so forth.

Table 9

System Security Needs and "Essential Reliability Services"

Services	Components		Description	Consequences of Failure
Voltage Support	*Voltage Control*		Support system load; maintain transmission system in a secure and stable range	· Loss of Load · Equipment Failure · Cascading Losses
	Voltage Disturbance Performance		Ability to maintain voltage support after a disturbance	
Frequency Management	*Operating Reserves*	Regulation	Minute-to-minute differences between load and resources	· Loss of Generation · Load Shedding · Interconnection Islanding · Overload Transmission Facilities · Damage Equipment and lead to Power System Collapse
		Load Following	Intra- and inter-hour load fluctuations	
		Reserves	Includes Spinning, Non-Spinning, and Supplemental; Used for synchronization and respond to generator or transmission outages in 10 min or greater time frames	
	Inertia		Stored rotating energy; Used to arrest decline in frequency following unexpected losses	
	Frequency Distribution Performance		Ability of a plant to stay operational during disturbances and restore frequency to BPS	
	Active Power Control	Frequency Control	Real-time balance between supply and demand	
		Ramping (Curtailment) Capability	Ability to increase/decrease active power, in response to operator needs. Measured in MW/min basis	

Notes and Sources:

[1] Adapted from NERC (2014) "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability".

[2] NERC (2014) notes that these Essential Reliability Services are functionally equivalent to the Interconnected Operations Service (IOS) definitions, with Voltage Support covering Reactive Power Supply from Generation Sources and Frequency Support covering Frequency Response, Regulation, Load Following, and Contingency Reserves.

[3] NERC notes that many of these ESRs are already defined as ancillary services in the OATT of many system operators. Ancillary services are "those services necessary to support the transmission of electric power form seller to purchaser", considering reliabilty needs. Therefore, NERC considers ancillary services to be a subset of ESRs.

Second, the operator must maintain frequency and voltage on the system at all times. This means, for example, starting up plants as backup resources ("reserves") to quickly replace another plant that trips off line or dips in its output (e.g., due to changes in wind conditions or power plant failure), or adjusting power output up and down with little notice to meet swings in load.

Third, the operator maintains and draws on a diverse set of operational procedures to manage system performance – such as committing or "posturing" resources that may be needed, allowing minor variations in system voltage, calling on resources from neighboring regions,

disconnecting variable generation, signaling to 'demand-response' providers to curtail their loads within short periods of time, and other procedures (including, as a last resort, isolated involuntary disconnection of load – or "rolling blackouts").

Reliability is by nature a technology-neutral concept. That said, not all of a system's resources are equal when it comes to the attributes they provide to system operators to manage system security. Historically, power systems' needs for voltage support, inertia, frequency control, and contingency-response capability have been met through operator actions in conjunction with their commitment of the types of technologies on the system: traditional thermal steam units (e.g., coal, nuclear, oil plants, natural gas and combined heat and power units) providing baseload service around the clock; cycling and load-following technologies (e.g., combined cycle plants operating on natural gas); quick-start fossil-fired peaking plants; and dispatchable hydro power supplies.

As the technologies on the system change – which is happening to different extents in different regions as a result of various forces, with or without the Clean Power Plan (as described above in Section I) – steps are being taken to ensure that the suite of essential reliability services is available to supply the frequency/voltage control and contingency-reserve needs of the system. NERC has characterized the challenge as one of filling gaps in services as they arise or widen over time.

Notably, system planners across the country are dealing constantly – and so far successfully – with the new and emerging reliability challenges from changing technology mixes. For example, the CAISO and California electric utilities have identified the need to add greater ramping capability to handle an increased variability in intra-day loads introduced from increasing amounts of 'variable energy resources' (VERs) necessary to meet increasingly higher renewable portfolio standards.[42] In general, load following is typically accomplished through the dispatch of fast-ramping combustion turbines and natural gas combined cycle (NGCC), although load following can also be met through well-designed and cost-effective storage, optimized energy efficiency programs, demand response, and devices (such as smart inverters) being added to wind farms.

[42] California is on track to meet its renewables portfolio standard target, such that by 2020, 33 percent of its total energy comes from renewable resources. The state is considering whether to adopt a 50-percent goal by 2030. Behind-the-meter solar and wind supplies are projected to significantly decrease net load during the middle of the day, while leaving significant shoulder peaks in the morning and evening, resulting in what is commonly called the "duck curve." A recent analysis found that this will require a significant increase in fast ramping, flexible dispatchable generation resources (along with other technologies, including storage). See Energy+Environmental Economics (E3), "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

III. What Concerns are Commenters Raising About Reliability Issues Associated with EPA's Clean Power Plan?

Summary of comments

To date, the EPA has received more than 3 million comments on the proposed Clean Power Plan. Many comments have raised concerns about electric system reliability. These comments have come from a wide range of stakeholders, including: owners of affected power plants (including vertically integrated utilities, merchant generators, municipal electric utilities, cooperatives); state officials, including public utility commissions, air pollution regulators, energy offices, as well as governors, attorneys general, and consumer advocate offices, and associations representing these various groups of public officials; system operators, regional reliability organizations; trade associations with business, public health, environmental, fossil-fuel supply and delivery organizations; members of the public; and others.[43]

The many comments received on reliability issues reflect the importance of thinking clearly about the potential impacts of the Clean Power Plan on system reliability. We summarize the types of reliability-related comments in Table 10, below, and provide more information about these public comments in the Appendix. Notably, EPA has made it clear that system reliability needs to be maintained as the Clean Power Plan is finalized and implemented.[44]

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[43] Among the latter include various electric industry organizations (e.g., the Edison Electric Institute; the APPA; the National Rule Electric Cooperative Association; the Electric Power Supply Organization; the Clean Energy Group); business associations (e.g., the Chamber of Commerce); gas industry organizations (e.g., the Interstate Natural Gas Association (INGAA)); coal-industry groups (e.g., the Coal Utilization Research Council); non-energy trade groups (e.g., Water Associations such as the American Water Works Association, National Association of Water Companies and the National Association of Clean Water Agencies), and environmental organizations (e.g. Natural Resources Defense Council and Environmental Defense Fund); NERC; various individual RTOs (MISO, PJM, NYISO); FERC Commissioner Philip Moeller; Senator Dan Coats and 22 other senators. This is not intended to be a comprehensive or exhaustive list of comments or commenters, but rather represent the broad cross-section of types of organizations with an interest in Clean Power Plan reliability issues. Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[44] For example, see both the Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Federal Register, Vol. 79, No. 117, June 18, 2014. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf, and the Technical Support Document: Resource Adequacy and Reliability Analysis. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-resource-adequacy-and-reliability-analysis

Table 10
Summary of Reliability Concerns Raised in Public Comments and Which Need to be Addressed as the EPA's Proposed Clean Power Plan is Implemented

Summary of Comments Submitted on Reliability Issues Related to the EPA Clean Power Plan		
Category	**Description**	**Potential Reliability Considerations – Which Need to be Addressed**
Resource Adequacy	Retirements of baseload power plants are presenting on-going challenges in some regions	May tighten planning reserve margins in some regions and require timely replacement of capacity on a 1-to-1 basis
		Requires additional transmission planning and analyses, with transmission solutions typically having longer lead times (~10 years) than generation additions
Resource Mix and Operational Security	Retirement of coal-fired capacity and restrictions on output at coal plants, combined with greater use of gas-fired capacity, will result in less fuel diversity in various regions	Some coal units will/may be cycled more frequently, ending up with lower overall capacity factors and adversely impacting relevant heat rates (and emissions per MWh)
		Operating gas plants at higher output will depend upon having adequate gas delivery capability, including firm supply and delivery contracts
		Increased reliance on variable and non-dispatchable resources (like wind and solar) will mean the need for greater quantities of operating reserves and ramping capability
		Loss of baseload generation requires additional voltage and frequency Support, including Inertia
Planning and Regulatory Coordination	The interim goals established in the Clean Power Plan do not provide adequate time for planning and development of adequate resources, for state and regional coordination, or for market solutions	Lead times for new transmission and power plants (including planning, siting, permitting, and construction time lines) extend beyond 2020 and the interim deadlines)
		Successful resolution of various gas-electric coordination issues will be needed to support greater reliance on natural gas in many regions
		RTO/ISO rules and practices regarding security-constrained economic dispatch may need to be reviewed and/or updated, depending upon how states design their plans to incorporate emissions controls
		Greater reliance on demand response and energy efficiency may require new rules and forecasting capabilities in wholesale energy and capacity markets
		Allocation (or reassignment) of transmission rights may be needed to accommodate changing power flows following power plant retirements or to accommodate greater reliance on underutilized gas-fired capacity and/or renewable resources.
Market Impacts and Market Responses	Uncertainty surrounding final regulations and state plans make it hard for markets to respond with concrete proposals in timely fashion	Uncertainty surrounding the regulatory treatment of new gas-fired combined cycles (under 111(b)) may chill development
		Increased reliance on gas-fired power plants may depend upon new investment in pipeline capacity, with need for new mechanisms to support long-term commitments in some regions (e.g., organized markets)
		Increased reliance on natural gas may accelerate retirements of nuclear units prior to the end of their operating licenses.
		Reliability must-run contracts may be needed to retain some units needed for reliability, but with potential adverse impacts on wholesale market efficiency
		Uncertainty surrounding how states will plan for ensuring new capacity additions in regional organized markets, in light of buyer-side mitigation and other federal wholesale market rules

Many observers' concerns that the Clean Power Plan could jeopardize *resource adequacy* are tied primarily to questions around timing: Does the sequence of steps implied by EPA's proposal – starting with the June 2014 proposal, then taking into account the timing of EPA's final rule, the development of State Plans, the approval of plans by the EPA, and then through compliance

decisions and actions by owners of affected power plants – allow sufficient time for everything that needs to be done by states, reliability planners, grid operators, planning and procurement processes, market responses, and so forth to ensure resource adequacy? Or, where that is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing resource adequacy?

Concerns voiced about whether Clean Power Plan implementation could jeopardize *system security* are tied primarily to anxiety over how and when state compliance activity will alter the diversity of resources on the system, and thus the mix of resource capabilities needed to meet system security requirements. In particular, will the economic signals and compliance obligations provided through state implementation of the Clean Power Plan cause the retirement of resources that are needed for system security, and/or will replacement capacity provide the needed operational capabilities? If a significant portion of existing coal-fired capacity retires and is replaced (in part) by gas-fired capacity, will regional interstate pipeline systems be robust enough to ensure reliable delivery of fuel in all hours of the year? If state compliance activities significantly increase the proliferation of grid- and distribution-level variable resources, how much more difficult will it be for system operators to manage the variability in net load on a real-time basis? Or, where this is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing system security concerns?

Other commenters portray the readiness of the industry to step up with solutions to these reliability issues. For example, INGAA described the capability of the natural gas pipeline industry to add new infrastructure.[45] Calpine stated its readiness (along with other market participants) to add new gas-fired generation (and to offer under-utilized capacity already existing on the system).[46] The Clean Energy Group provided suggestions about how the design of policies supporting flexibility and market-based approaches can substantially mitigate reliability concerns.[47] State energy offices (through their national association (NASEO)) noted the ability of a wide variety of well-tested energy efficiency measures (beyond utility-provided programs) to avoid CO_2 emissions from power plant operations.[48] The National Association of Regulatory Commissioners (NARUC) pointed to the ability to reap cost-effective savings in the

[45] Comments of INGAA, filed December 1, 2014.

[46] Comments of Calpine Corporation, filed November 26, 2014.

[47] Comments of the Clean Energy Group (CEG), filed December 1, 2014.

[48] Comments of the National Association of State Energy Officials (NASEO), filed December 1, 2014.

electricity used for water treatment and delivery by introducing measures on the water utility system – thus affording water savings and avoiding CO_2 emissions on the power system.[49]

We also point out many ways to address the reliability issues raised in comments in Section IV of our report, with our suggestions organized around the different entities with some direct or indirect role to play in system reliability.

Reliability safety value concept

The ISO/RTO Council (IRC) has proposed that EPA include a "Reliability Safety Valve" provision as part of the final rule, to help with resolve multi-state issues that may arise due to the Proposed Rule and impact grid reliability.[50] In the view of the IRC, a Reliability Safety Value would provide a regulated and reviewed backstop solution with a defined process for modifying State Plans to ensure reliability against unforeseen issues. As part of this process, the IRC has recommended that the EPA include a specific requirement in the final rule that State Plans must include a detailed reliability assessment. By requiring reliability assessments ahead of final plans, according to the IRC, the Reliability Safety Valve would only be used in situations that could not be addressed ahead of time and that arise solely from dynamic, unplanned changes in the grid. As proposed by the IRC, a Reliability Safety Value would allow relief from compliance schedules if specific units are deemed necessary for reliability considerations.[51] The Reliability Safety Value has been supported by numerous organizations and RTOs, who point out that the concept has been successfully implemented as part of the MATS compliance policy.

We note – as an important element in considering the particular Reliability Safety Valve proposed by the IRC – that there are key differences between the regulatory frameworks of Clean Power Plan and the MATS rule. In particular, the latter assigns emissions-reductions targets on each affected fossil-fuel generating unit, and does not allow any emission averaging across generating stations or across time. As we noted previously in this report, there is much more flexibility in the design of the Clean Power Plan.[52] In particular, the opportunity for states

[49] Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed November 19, 2014.

[50] For example, see comments filed by the ISO/RTO Council (IRC), December 1, 2014.

[51] This process is analogous to RMR contracts that are often available in organized ISO/RTO markets. These contracts provide for time-limited, out-of-market payments to generators that have provided notification of retirement but are necessary for reliability reasons (e.g., local voltage support). Once alternative resources (transmission or generation) solving the reliability need are in place, the RMR contracts cease and the units may retire. By way of example, the IRC suggests that the Reliability Safety Value and a mandatory reliability assessment could help identify reliability issues arising from an individual State Plan, such as a state requirement for reduced utilization at a fossil unit needed for transmission security and voltage support on a transmission network that crosses a state line. ISO/RTC Comments, filed December 1, 2014.

[52] EPA is relying on a portion of the Clean Air Act– Section 111(d) – in its Clean Power Plan. "Section 111(d)'s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to

to rely upon market-based mechanisms that allow emission trading across power plants within states and across wide regions is a compelling basis for thinking differently about the need for a reliability safety value in this instance. The wider the region in which emission trading might occur, the less likely that reliability issues will be introduced by the Clean Power Plan.

NERC's initial reliability assessment of the Clean Power Plan

NERC published its own "Initial Reliability Review" of the Proposed Rule in November 2014.[53] NERC flagged a number of "significant reliability challenge[s], given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed [Clean Power Plan]."[54] NERC notes that the primary purpose of the paper was to "provide the foundation for the range of reliability analyses" that will be required for stakeholders to work together. Notably, NERC recommended that coordinated regional and multi-regional planning and analysis should start immediately to identify specific areas of concern and that the EPA should consider a more timely approach to resolving any known reliability concerns.

NERC noted that the accelerated retirement of fossil units will stress already declining reserve margins, and that time will be a major constraint, particularly for facility planning, permitting, and construction. NERC identifies transmission upgrades as potentially being needed to successfully integrate variable energy resources anticipated as part of various states' plans, as well as to support reliability concerns regarding voltage and frequency support associated with extensive re-dispatch of NGCC. NERC also suggested that pipeline capacity constraints will

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other recent federal regulatory initiatives applicable to the electric industry.… In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources. By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance… And in its [State Plan], each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach. This language "supports the use of market-based mechanisms" and other alternatives in ways that are not possible under the statutory language governing MATs, which required each affected generating station to have emissions at or below the allowed emissions rates. If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another." Source: Susan F. Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 2014, pages 3-4.

[53] NERC has stated that its November report, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review," November 2014 (Hereinafter referred to as "NERC CPP IRR") is the first in a series of reliability assessments that NERC plans to conduct. NERC says it plans to release two additional studies in 2015 that will include a detailed evaluation of generation and transmission adequacy and a preliminary assessment of state SIPs.

[54] NERC CPP IRR, page 2.

exacerbate the strain on essential reliability services from relying more heavily on gas. While a full review of the NERC study is beyond the scope of this paper, we note again that these issues have been emerging in markets for a number of years, well before the introduction of the Clean Power Plan. Indeed, NERC covered these "emerging trends" in California, Hawaii, ERCOT, and other regions in its October primer on "Essential Reliability Services."

Many comments in turn, have cited and expanded on the NERC Review. While reliability has been a common theme of these comments, for the most part the NERC report and the public's comments on the Clean Power Plan do not point to specific, modeled reliability problems that have been identified at known points on the bulk power system. Rather, both the report and the comments focus on generalized concerns about potential reliability issues that may arise due to the operational challenge of meeting both the interim and final-goal targets, generally assuming little in the way of the compliance flexibility built into the proposed rule and available to states. While these are valid concerns, it is critical to recognize the numerous strategies, policies, markets and organizations in place that have successfully dealt with these similar operational challenges in the past, and will going forward, as we discuss further below.

Moreover, the Clean Power Plan proposed rule, like all proposed EPA rules, is a "first draft" that is designed to elicit data and comments. EPA has already signaled that it is evaluating stakeholder concerns about the timing and glide path for meeting interim and final targets, and will evaluate this information as it writes the final rule.

Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided and addressed in time through planning and infrastructure – we do note recent critiques (e.g., Brattle Group's February 2015 report) of the assumptions used in NERC's recent reliability assessments, which do not take into consideration industry responses to market and reliability signals. This is a significant reason to view the NERC as only having set the table with respect to potential reliability concerns, and to recognize that NERC and many other parties will step up with their important contributions to implementation of the CPP within the electric system reliability context.

IV. Options for Assuring Electric System Reliability in Conjunction with Implementing the Clean Power Plan

The reliability check list

The many comments on the proposed Clean Power Plan submitted to EPA serve as a reminder of the broadly-understood condition that pursuing CO_2 emission reductions in the power sector has to occur in an environment that respects the reliability rules of the game. Like the check list at the start of any endeavor, the comments point out a number of potential items to consider adding to the "to do" list that the electric industry routinely uses to ready itself for reliable system operations.

http://imgkid.com/checklist-icon.shtml

Fortunately, that check list is already robust. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations, placing the country in a good starting position as of the start of 2015. Many of the reliability issues identified in public comments are not new – the industry has responded successfully and effectively to similar challenges in the past. And for several years, some of the trends that commenters note must now be addressed in response to the Clean Power Plan are actually developments that have been underway for many years – and that are currently being addressed. Examples include the FERC's policies addressing: transmission planning taking into account infrastructure needs arising from state-policy (such as renewable portfolio standards); integration of variable electric resources; market designs to assure efficient entry of capacity with attributes needed for reliable system operations; and directives to modify standards and policies so as to better harmonize operations of the electric and gas markets. Other examples include the many studies conducted by RTOs, electric utilities, national laboratories (like the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), research institutions (such as the Electric Power Research Institute, university research centers, and think tanks) , and the Department of Energy.

These many studies are already pointing out that some of the tools and checklists needed for reliability may need to be enhanced as a result of the many changes underway in the industry. In many respects, the shift towards natural gas-fired generation (driven in large part by fundamental economic forces), the proliferation of variable resources due to economic and policy factors, and the growth in distributed resources in some regions will drive changes in industry planning and operations over a schedule largely coincident with implementation of the Clean Power Plan.

In the end, we think that even if sometimes exaggerated, the reliability "alerts" are actually a good thing: It is appropriate that people are paying attention to reliability issues, so that potential problems can be avoided – and they can be addressed in time through proper planning and appropriate responses. Even if some of the existing tools need to be sharpened or even new ones added, past experience, the capabilities of the industry, the attention of regulators, and the inherent flexibility of Clean Power Plan implementation strongly suggest that the task is manageable. As always, careful planning and advance work is necessary to make sure that there are not inefficient trade-offs between the two core objectives.

The Reliability Toolkit: Which ones to use here?

The U.S. electric system performs so reliably because it includes both clearly defined and clearly assigned roles and responsibilities to particular actors, and also relies upon markets and regulated planning processes to provide an array of workable solutions. This is a very sturdy toolkit to build upon. Our suggestions aim to make it even better by pointing out some extra steps that responsible parties might take to make the toolkit as strong as possible for supporting the changes underway in the industry, including Clean Power Plan implementation.

For this reason, we organize our discussion of tools by identifying those in the hands of "reliability organizations" (like grid operators, FERC, NERC, the states, and others) and those in others' hands (including power plant owners, the markets, and many additional players, including the EPA itself). While the latter may not be "reliability organizations" in the same ways that the institutions in the first group are, they still have significant opportunities (if not genuine responsibility) to take actions to help ensure reliable pathways to compliance with CO_2 emission reductions required from the power sector.

In Table 1 at the beginning of our report, we categorize parties into the following groupings:

- Entities with direct responsibility for critical reliability functions;
- Other public agencies with direct or indirect roles in the Clean Power Plan;
- Owners of existing power plants covered by Section 111(d) of the CAA;
- "Markets" and resource planning/procurement organizations; and
- Other entities with inevitable roles to play in ensuring a reliable system in conjunction with enabling effective and timely compliance with the Clean Power Plan.

Note that in some cases, some parties (e.g., a vertically integrated utility which is a balancing authority and also conducts resource/planning and procurements) may fall into one or more categories.

Then we use those groupings not only to identify the normal, business-as-usual responsibilities of those parties, but also to make a number of suggestions for things that those different players might do in anticipation of heading off potential reliability problems before they arise, or in mitigating impacts if they do. Table 2 makes suggestions for what FERC, NERC, the Regional Reliability Organizations, with Table 3 providing suggestions for System Operators/Balancing Authorities might do, in terms of institutionalizing new studies, reporting requirements, and so forth. Table 4 then focuses on things that other federal agencies can do, with Table 5 suggesting actions by state government entities. Table 6 identifies potential actions that might be considered/adopted as part of organized markets to send appropriate and timely signals for investment, and in parallel, what electric utilities might do within their own resource planning/procurement processes to accomplish reliable outcomes in their geographic footprint. Finally, Table 7 provides a number of suggestions about things that other players might do in their own zones of influence.

In the end, the industry, its reliability regulators and the States have a wide variety of existing and modified tools at their disposal to help as they develop, formalize, and implement their respective State Plans. These two responsibilities – assuring electric system reliability while taking the actions required under law to reduce CO_2 emissions from existing power plants – are compatible, and need not be in tension with each other as long as parties act in timely ways.

This is not to suggest that electricity costs to consumers do not also matter in this context; of course they do. But we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution, precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

This array of tools is of course subject to important and beneficial social constraints and must be exercised to serve the interests of ratepayers. There is no reason to think that these dual objectives cannot be harmonized within a plan to reduce carbon pollution.

V. Conclusion

In this report we identify the many rules, regulations, institutions, and organizations – in effect, the industry's *standard operating procedures* – for ensuring that EPA's design and administration of the Clean Power Plan in no way jeopardizes or compromises the high level of power system reliability we are used to. Such reliability is essential for the strength of our economy and the public health and safety of our citizens.

In the end, of course, it is a good thing that the industry is paying close attention to reliability issues, so that any potential problems can be avoided – and can be addressed in time through planning and appropriate responses. This is do-able, based on past experience and the capabilities of the industry. As always, careful planning and advance work is necessary to make sure that there are not trade-offs between the two.

Having reviewed the broad range of comments received by EPA with a focus on power system reliability, and the potential reliability challenges posed by Clean Power Plan administration, we find that many of these comments tend to assume inflexible implementation and present worst case scenarios, with an exaggerated cause-and-effect relationship. Moreover, many comments (including those from NERC itself) tend to assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. The history of the electric system and its ability to respond to previous challenges including industry deregulation and previous Clean Air Act regulations such as the NO_x SIP call, SO_2 rule, CSAPR, and MATS prove that this is highly unlikely. These challenges will be solved by the dynamic interplay of regulators and market forces with many solutions proceeding *in parallel*.

Indeed, this dynamic interplay is one reason why a recent survey of more than 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and felt that EPA should either hold to its current emissions reduction targets or make them more aggressive.[55] Similarly, other market participants announced a willingness and ability to help meet system demand for new natural gas supplies[56] and gas-fired generation, in

[55] The same survey found that those utility executives believed that distributed energy resources offered the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, 2015 State of the Electric Utility Survey Results, January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned, municipal, and electric cooperatives.

[56] See, for example, comments filed by INGAA, December 1, 2014. ("INGAA is confident that … the natural gas pipeline industry can respond to demand for the natural gas pipeline capacity that may be necessary to enable compliance with the Clean Power Plan."). INGAA noted that the existing natural gas pipeline system is already supporting national gas-fired combined-cycle utilization rates of 60 percent during peak periods, which are the same periods when distribution constraints are most likely.

support of the Clean Power Plan.[57] This is in addition to the expanded and innovative solutions and strategies for incremental energy efficiency and distributed energy resources identified by State Regulators and Energy Officials.

There are a number of things states and others can (and, in our view, should) do as part of developing their State Plans to further ensure reliability. First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has relied on to maintain reliability for decades – in the face of both normal operations and sudden changes in markets and policy. These procedures flow from a comprehensive set of laws, rules, protocols, organizations, and industry structures that focus continuously on what is needed to maintain electric reliability.

Second, states should give due consideration to the vast array of tools available to them and the flexibility afforded by the Clean Power Plan in order to ensure compliance is obtained in the most reliable and efficient manner possible. In particular, given the interstate nature of the electric system, we encourage states to enter into agreements with other states or add provisions to state plans that facilitate emission trading between affected power plants in different states; doing so will increase flexibility of the system, mitigate electric system reliability concerns, and lower the overall cost of compliance for all.

[57] See, for example, the comments of Calpine Corporation, filed November 26, 2014. ("With our modern, flexible, and efficient generating fleet, Calpine is prepared to facilitate the successful implementation of the Proposed Clean Power Plan. We are confident that by working constructively with the states and EPA as we have always done, the Clean Power Plan can be a success.")

APPENDIX:
Public Comments on EPA's Proposed Clean Power Plan: Summary of Concerns Relating to Electric System Reliability Issues

As of February 8, 2015, 3.83 million comments have been filed on the EPA's proposed Clean Power Plan.[58] Many organizations have compiled lists and summaries of comments filed by various parties.[59] Most of the comments focus on stringency of the proposed emissions reductions targets, the reasonableness of (and legal bases for) the "building block" methodology used by EPA is setting state targets, the timing of emissions reductions in two periods (interim: 2020-2029); and final (2030 and beyond); the ability of states to develop their State Plans with enough time; and other comments.[60],[61]

[58] Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[59] See, for example: Bipartisan Policy Center (http://bipartisanpolicy.org/wp-content/uploads/2015/02/Comments_Map_Static.pdf); National Association of State Energy Offices (http://111d.naseo.org/); Advanced Energy Economy (http://blog.aee.net/epa-ghg-regs-we-read-the-comments-so-you-dont-have-to-part-1-state-federal-regulator-association); Institute for 21st Century Energy (U.S. Chamber of Commerce); (http://www.energyxxi.org/eparule-stateanalysis; http://www.energyxxi.org/eparule-stateanalysis).

[60] See, for example, comments filed by APPA, December 1, 2014; Business Roundtable, December 1, 2014; Class of '85 Regulatory Response Group, December 1, 2014; CEG, December 1, 2014; CURC, December 1, 2014; Coalition for Innovative Climate Solutions, December 1, 2014; Edison Electric Institute (EEI), December 1, 2014; Electric Power Supply Institute, December 1, 2014; ERCOT, November 17, 2014; Environmental Defense Fund, December 1, 2014; Georgetown Climate Center (with state officials from California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington), December 1, 2014; INGAA, December 1, 2014; NARUC, November 19, 2014; NASEO, December 1, 2014; NRDC, December 1, 2014; National Rural Electric Cooperative Association, July 29, 2014; Nuclear Energy Institute (NEI), December 1, 2014; NYISO, November 17, 2014; PJM Interconnection, December 1, 2014; RTO/ISO Council, December 1, 2014; Sierra Club, December 1, 2014; Southern States Energy Council, September 29, 2014; and Western Electricity Coordinating Council (WECC), November 25, 2014.

[61] Even before the final December 1st, 2014 deadline for filing comments, the EPA and other regulators had acknowledged these many public statements and the comments that had been submitted in advance of the deadline. Specifically, in October of 2014, EPA issued a Notice of Data Availability (NODA) that sought comments on three core issues, which we summarize below:

- *Compliance trajectory of emissions reductions from 2020 to 2029*, and in particular, if or how reductions related to building block 2 could be phased in over time (for example, to accommodate constraints in natural gas distribution infrastructure, or how the book life of existing assets could be used to define an alternative glide path) or how states could earn compliance credits for actions taken between 2012 and 2020;
- *Technical assumptions in the building block methodologies for 2 and 3*, including how to consider new gas-fired combined cycle (NGCC) units in state goals, the role of natural gas co-firing at coal plants as a compliance strategy, and if states with little to no existing NGCC capacity should achieve a minimum target of new NGCC generation; and with respect to renewable energy, how or if the EPA could consider alternative goal setting strategies that account for state or regional economic potential of renewables as opposed to relying on existing RPS; and the role of nuclear units in building block 3; and
- *Methodologies for setting State-specific goals*, including the feasibility of using a multi-year baseline (2010-2012) for goal setting, to what extent renewable and energy efficiency goals should be assumed to displace existing fossil generation – as opposed to displacing or avoiding future fossil generation.

The formal NODA is available through Regulations.Gov in Docket No. EPA-HQ-OAR-2013-0602 and informally, through the EPA, here: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-notice-data-availability.

Our own review of submissions from the public and various organizations has focused on issues related to system reliability. These commentaries include concerns raised about one or another aspect of the proposal's impact on the power system's performance. Many comments make suggestions for changes in EPA's proposal, and steps that other entities might take to address reliability issues in the context of compliance with the Clean Power Plan.

A common reliability-related comment is that the EPA did not consider – or seek out the expertise – for how the assumptions it used in setting states' emission reduction targets (i.e., the four "building blocks") may change the operations of the electric grid and how those changes in turn can affect the ability to meet state targets.[62] A similar theme is that the individual state targets do not account for the regional nature of electric grid reliability. Finally, a common concern is that the proposed timeframes for compliance, combined with the interim targets for emissions reductions commencing in 2020, do not provide adequate time for states to develop regional compliance plans or for RTOs to incorporate State Plan provisions into the regional long-term planning frameworks or existing market rules for economic dispatch.

That said, a wide range of regulators and other organizations have committed to working with the EPA and the states to manage these challenges, and in turn, leverage their detailed knowledge of the electric system. As discussed later in this report, many regional coordinators and state regulators already have planning policies and procedures in place that can proceed in parallel with the development of SIPs to ensure the timely development of generation, transmission, and distribution infrastructure needs.[63]

Although the comments do not point to specific known, localized reliability problems identified by a specific commenter, many observers caution that if a state elects not to (or cannot, for one reason or another) accomplish the depth of emission reductions assumed by EPA in state

[62] For example, the EEI noted that "a significant portion of [it's] comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system." Comments filed December 1, 2014, at 12. Similarly, on December 22, 2014, Senator Murkowski (ranking member, Committee on Energy & Natural Resources), Representative Upton (Chairman, Committee on Energy & Commerce), and Representative Whitfield (Chairman, Subcommittee on Energy & Power) requested comment from the FERC Commissioners on their level of involvement and interaction with EPA staff when developing the Clean Power Plan and understanding reliability implications. Letter to FERC from Senator Murkowski, Representative Upton, and Representative Whitfield, December 22, 2014.

[63] Note for example, recent activities among the PJM states: the recent comments submitted to the FERC (Docket No. AD15-4-000: Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, February 19, 2015) by Michael Kormos, Executive Vice President for Operations, PJM: "PJM has begun this coordination process by engaging state commissions, state environmental regulators responsible for implementing the Clean Power Plan, and EPA starting last year. Recently, PJM has undertaken detailed analyses of scenarios and alternatives that were provided to us by OPSI. Those results have been reviewed with our members and with the states and are posted on our website at http://www.pjm.com/~/media/committeesgroups/committees/mc/20150120-webinar/20150120-item-05-carbon-rule-analysis.ashx.

targets, then the state will inevitably need to make additional cuts from other blocks which will increase the stress on remaining assets and strategies.

Comments on reliability issues thus tend to focus on challenges in system operation that may lead to reliability failures. The commentaries do, however, provide suggestions for how to mitigate the challenges for system reliability failures by building into State Plans alternative strategies for meeting those same targets beyond those incorporated into EPA's target-setting assumptions. For example, comments by both NARUC and NASEO discuss the extensive potential for additional CO_2 savings from energy efficiency projects at the interface of the energy-water nexus and other energy-efficiency initiatives outside of conventional programs administered by electric utilities. Additional guidance or clarification from the EPA on how to account for these programs in State Plans could unleash and incentivize a broad swath of carbon reduction strategies beyond the narrow four building blocks.

Many comments focused on the implications of greater utilization of natural gas-fired power plants on changes in system dispatch and the interdependence of interim and final state goals.[64] Achieving a system-wide 70-percent capacity factor for existing natural-gas combined cycle (NGCC) units, for example, would transition a set of power plants now used largely as intermediate and load-following resources to become base-load capacity resources. Baseload coal-fired generators in place at the end of the 2010s would feel the effects, through either greater cycling of these units, or retention of the units to operate only occasionally if needed to remain on the system for resource adequacy purposes, or retirements. Observers note that cycling such coal-fired units more frequently will decrease their efficiency (i.e., increase their heat rates), as plants use additional energy to overcome the inertia inherent in these units. Commenters' cautions that such impacts will increase the overall fleet average emission profile. The observation is that such interactions will mean that states will need to find additional carbon reductions elsewhere. To the extent that the shift includes greater reliance on renewable energy penetration, then the system operators will need to adjust how they operate the resources on their system to maintain reliability. These variable energy resources do not offer system operators the same level of control (e.g., some may be behind the meter and therefore not even "visible" to operator) for frequency or voltage support nor can they be relied upon to meet load in all hours of the day. In the absence of significant new storage capability on the system, this will increase the need for load-following, fast-ramping resources to respond to

[64] The U.S. Chamber of Commerce Institute for 21st Century Energy reviewed and summarized State comments and found that 35 states raised issue with Building Block 2. This was more than any other category identified by the report. Institute for 21st Century Energy, U.S. Chamber of Commerce. "In Their Own Words: A Guide to States' Concerns Regarding the Environmental Protection Agency's Proposed Greenhouse Gas Regulations for Existing Power Plants", January 22, 2015, page 14.

sudden drops in renewable generation. Traditionally, gas-fired combined cycles or natural gas combustion turbines have met this need. But gas-fired plants that begin to operate more in baseload mode may not be able to perform that load-following function. As described in Section II, Figure 2 above, lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades.

These changes are already underway in part due to the shale gas revolution, state and federal policies supporting renewable energy, other environmental policies. According to some observers, the Clean Power Plan will accelerate such trends. Either way, grid operators will need to address the potential diminishing reservoir of voltage support and inertia that has historically been supplied by coal-fired thermal units with their rotating mass of equipment.

Also, the successful operation of natural gas combustion turbines to balance and integrate intermittent and variable renewable supplies will depend, in turn, on the availability and access to fuel when needed for dispatch. Commenters have suggested, and rightly so, that a significant increase in gas-fired generation will require new gas delivery infrastructure. (We note the recent report published by the U.S. DOE that found, among other things, that the amount of incremental gas infrastructure needed is less than what has been put in place by the industry in the recent past.[65]

> Diverse sources of natural gas supply and demand will reduce the need for additional interstate natural gas pipeline infrastructure. The combination of a geographic shift in regional natural gas production—largely due to the expanded production of natural gas from shale formations—and growth in natural gas demand is projected to require expanded natural gas pipeline capacity. However, the rate of pipeline capacity expansion in the scenarios considered by this analysis is lower than the historical rate of natural gas pipeline capacity expansion. …
>
> (2) Higher utilization of existing interstate natural gas pipeline infrastructure will reduce the need for new pipelines. The U.S. pipeline system is not fully utilized because flow patterns have evolved with changes in supply and demand. …
>
> (3) Incremental interstate natural gas pipeline infrastructure needs in a future with an illustrative national carbon policy are projected to be modest relative to the Reference Case. While a future carbon policy may significantly increase natural gas demand from

[65] U.S. DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015, http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf. After modeling interactions between the gas and electric industries, the report's key findings (at iv-v).

> the electric power sector, the projected incremental increase in natural gas pipeline capacity additions is modest relative to the Reference Case.
> (4) While there are constraints to siting new interstate natural gas pipeline infrastructure, the projected pipeline capacity additions in this study are lower than past additions that have accommodated such constraints."

It will take time – in some cases several years – to build this infrastructure, and unlike transmission planning that is coordinated by a central planning authority, expansion of the gas delivery and storage system is driven by market economics. But significant amount of pipeline expansion is already in advanced planning and permitting. Thus, while typically, gas pipeline companies require long-term commitments from 'anchor' gas shippers before receiving permitting approval and proceeding to break ground, there is no reason to believe that the system will be short of capacity as a result of the Clean Power Plan. Indeed, such commitments have and can be made in many regions (notably, in Colorado, as part of the state's approval of Xcel's decision to replace parts of its coal fleet with gas-fired plants, or in the Midwest, where DTE Energy has committed to support pipeline expansion to access gas supplies in the Marcellus). In some organized wholesale electric markets, however, there may need to be changes in some market rules and/or new institutional commitments to induce new investment in firm pipeline expansion to make gas available to non-utility generators.

Another issue raised in many comments relates to the current uncertainty that exists with regard to how states may/should/will count *new* gas-fired combined cycle power plants in their overall planning. Because such new plants fall under a different part of the Clean Air Act (i.e., Section 111(b)) than existing power plants (i.e., Section 111(d)), EPA has suggested that states will have the option to determine whether to fold in new plants into their overall framework for controlling emissions of then-existing power plants, or to keep those new plants regulated under a separate regime. What states will do remains a critical unknown, and could affect the operations of the overall power system, as well as emissions from the plants now covered under the Clean Power Plan.[66]

Beyond regional concerns and detailed technical criticisms, the most frequent reliability-related comments focus on the implications of the interim targets and the timelines for compliance.[67]

[66] For example, states with an emission rate goal less than 1,000 lbs/MWh may meet such a target through extensive renewable resources. The use and reliance on new NGCC units (with an emission rate equal to 1,000 lbs/MWh) to provide significant quantities of energy when renewables are off-line may actually increase net total emissions.

[67] The current rule includes two compliance options: a 2030 final goal with an interim compliance goal for average emissions between 2020 and 2029, and a second option, with lower total goals and no interim goals, to be achieved by 2025. Under option 1, States are required to file their SIP by June 30, 2016, with one year extensions available for single states and two years for multi-state plans. EPA has committed to reviewing and approving all SIPs within one year of receipt. Therefore, final SIPs will take effect

Commenters point out that the compliance timeline presents at least two challenges. The first is the added pressure on resource adequacy in light of pending retirements, particularly of economically marginal coal units facing difficult retrofit decisions for compliance with ongoing air regulations such as the MATS.[68] The second is the asserted lack of time for states to develop regional plans for compliance, which could easily require multi-year time frames to coordinate necessary staff in legislative departments, PUCs, and state energy and air offices.

Others have raised the issue that the timelines will result in significant stranded costs for ratepayers.[69] While not a reliability issue per-se, these stranded costs carry a true economic cost in that those monies may have been better spent on other programs in support of the Clean Power Plan project. However, as we discussed we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

between June 30, 2017 and June 30, 2019. Interim compliance goals for each state are set for the 2020 to 2029 period, in what is commonly referred to as the "glide path" of emission reductions to the 2030 target. The interim compliance goals assume that states can achieve the full quantity of reductions equal to estimates from Building Block 1 and Building Block 2. The "glide" in the interim targets, then, is due to the steady increase in carbon reductions from avoided fossil fuel generation in the 2020-2029 period from increasing levels of renewable energy and energy efficiency deployment.

[68] For example, MISO estimated that between 10 -12 gigawatts of coal-fired capacity will retire by 2016 to meet the MATS rule. An additional 14 gigawatts of coal-fired generation (25 percent of the remaining supply) is further at risk of retirement by 2020. MISO conservatively estimates that it will take a minimum of six years for the necessary generation and transmission infrastructure to replace these retirements. Assuming that all state plans are finalized and approved by 2018, necessary infrastructure would not be in place until 2024 – leaving a four year gap of increased reliability risk. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014.

[69] For example, Ameren estimated that the 2020-2029 interim timelines could cost Missouri ratepayers an additional $4 billion compared to its existing Integrated Resource Plan (IRP). Ameren noted that its existing IRP assumes the full retirement of coal units at the end of their useful lives by 2034. The early retirements would move forward the in-service date for proposed NGCC and require additional capacity than would otherwise be needed by 2034. See Comments of Ameren, filed December 1, 2014, at 3.

Acronyms

Acronym	Definition
APPA	American Public Power Association
BPS	Bulk Power System
BTM	Behind the Meter
CAA	Clean Air Act
CAISO	California Independent System Operator
CPP	Clean Power Plan
CO_2	Carbon Dioxide
CSAPR	Cross State Air Pollution Rule
CURC	Coal Utilization Research Council
CWA	Clean Water Act
EEI	Edison Electric Institute
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERSs	Essential Reliability Services
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
MATS	Mercury and Air Toxics Standard
MISO	Midcontinent Independent System Operator
NAAQS	National Ambient Air Quality Standards
NASEO	National Association of State Energy Officials
NARUC	National Association of Utility Regulatory Commissioners
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NODA	Notice of Data Availability
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection
PUC	Public Utility Commission
RPS	Renewable Portfolio Standard
RSV	Reliability Safety Valve
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SIPs	State Implementation Plans
SPP	Southwest Power Pool
VER	Variable Energy Resources (e.g., wind and solar)
WECC	Western Electric Coordination Council